RESPONSE TO SIGNIFICANT PUBLIC COMMENTS ON THE PROPOSED CLEAN AIR MERCURY RULE

Received in response to:

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 4652; January 30, 2004)

Supplemental Notice for the Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 12398; March 16, 2004)

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources, Electric Utility Steam Generating Units: Notice of Data Availability
(69 FR 69864; December 1, 2004)

Docket Number OAR-2002-0056

1.0 INTRODUCTION AND BACKGROUND
2.0 APPLICABILITY AND SUBCATEGORIZATION

US Environmental Protection Agency
Emissions Standards Division
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

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General Outline

1.0 INTRODUCTION AND BACKGROUND

The purpose of this document is to provide EPA's responses to public comments received on the notice of proposed rulemaking (NPR), "Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units" (Clean Air Mercury Rule; CAMR) (69 FR 4652; January 30, 2004); on the supplemental notice of proposed rulemaking (SNPR), "Supplemental Notice for the Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units" (69 FR 12398; March 16, 2004); and on the notice of data availability (NODA), "Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources, Electric Utility Steam Generating Units: Notice of Data Availability" (69 FR 69864; December 1, 2004).

The opportunity for written and oral public comment on the proposed rulemaking was announced with the NPR, the SNPR, and the NODA. Concurrent public hearings on the NPR were held on February 25 and 26, 2004, in Chicago, IL, Philadelphia, PA, and Research Triangle Park, NC. A public hearing on the SNPR was held on March 31, 2004, in Denver, CO. No public hearing was held on the NODA. The period for public comment on the NPR closed on March 30, 2004, but was extended to April 30, 2004, upon publication of the SNPR. Following numerous requests for an extension, the public comment period was reopened on May 1, 2004, and extended to June 29, 2004. The public comment period on the NODA closed on January 3, 2005. In addition, a telephone hotline was established for use by the public in providing comments.

EPA received approximately 500,000 comments on this proposed rulemaking, including numerous mass-mailings and approximately 5,000 "unique" comments. A listing of the commenters is provided in Appendix A to this document. A complete set of the public comments received (including the transcripts of the public hearings and telephone hotline calls) is available as part of eDocket OAR-2002-0056. This docket can be accessed at www.epa.gov/edocket or through the U.S. EPA Docket Center, 1301 Constitution Avenue, NW, Washington, D.C., 20004 in the Public Reading Room, Room B102, EPA West Building, 8:30 a.m. through 4:30 p.m., Monday through Friday.

A summary of the public comments received and EPA's responses is contained in the subsequent chapters of this document. In this document, EPA has followed the following three criteria:

- Detailed responses are provided only for those comments deemed to be significant. Other comments may be summarized and general responses provided.

- Comments determined to be "late public comments" on the NODA (i.e., received after the close of the public comment period for the NODA) are neither summarized in this document nor are responses provided. Comments received between June 30, 2004

(following the June 29, 2004, end of the public comment period on the NPR and SNPR) and November 30, 2004 (prior to the December 1, 2004, opening of the public comment period on the NODA) were considered in the decisions on the final rule because the comment period was reopened on December 1, 2004, if only on a limited number of issues. Responses are not provided to comments received after the close of the public comment period on the NODA on January 3, 2005, because there was insufficient time for adequate analyses of these comments.

- Comments received on the proposed Clean Air Act (CAA) section 112(d) maximum achievable control technology (MACT) approach and on the proposed approach to institute a cap-and-trade rulemaking under the authority of CAA section 112(n)(1)(A) have neither been summarized nor responded to in this document. We have taken this approach because these two proposed regulatory approaches, which were two of the three regulatory approaches proposed, were not selected for promulgation. Some commenters on CAA section 112(d) discussed alternative measures of what the proper emissions standards would be under a MACT, or criticized EPA's methodology for estimating those standards. To the extent these commenters have stated, or believe, that EPA should have performed additional MACT calculations, and compared these revised calculations with the emissions reductions achieved under CAA sections 110(a)(2)(D) and 111 before revising its 2000 CAA section 112(n) determination or promulgating CAMR, EPA disagrees. In assessing the effects of Hg emissions from U.S. utilities, EPA identified, to the extent possible given limits in data and modeling capability, all utility-attributable Hg emissions that deposit in the U.S. or otherwise affect U.S. public health. EPA used this information – what would happen if Hg emissions form U.S. utilities were eliminated completely – to identify the effects, and any remaining risks, of today's regulatory actions. Because EPA has concluded the effects and benefits of emissions reductions beyond those achieved through the Clean Air Interstate Rule (CAIR) and CAMR are small, and would not justify different decisions than those reached today, EPA has, therefore, not relied upon comparison between the emissions standards under a MACT and emissions after the actions adopted today.

2.0 APPLICABILITY AND SUBCATEGORIZATION

2.1 APPLICABILITY

2.1.1 Definitions

Comment:

One commenter (OAR-2002-0056-2922) stated that EPA uses the terms "coal-fired electric utility steam generating unit," "integrated gasification combined cycle electric utility steam generating unit," and "oil-fired electric utility steam generating unit" to define applicability in the proposed rules. However those terms are not defined anywhere in the proposed revisions (or the existing 40 CFR 60). EPA should add definitions for those units that are consistent with the definitions in proposed 40 CFR 60 Subpart UUUUU and with the public comments on those definitions.

Response:

EPA has provided the additional definitions, as appropriate, as suggested by the commenter.

Comment:

One commenter (OAR-2002-0056-2922) stated that EPA proposes to incorporate Hg and Ni standards into 40 CFR 60 subpart Da through section 60.45a(a) and (b) and section 60.46a, respectively. As revisions to the NSPS, applicability of those limits to new units is limited to units that commenced construction after the proposal date of January 30, 2004. EPA proposes to reflect that limited applicability only by means of parenthetical statements in the compliance provisions in 40 CFR 60 Subpart Da 60.48a(m) and (n). The commenters do not believe that EPA's approach is sufficient to make applicability clear. Instead, EPA should follow the approach it took with promulgation of a new output-based NO_x standard and also include a clear statement of applicability in the provisions setting out the new standards.

Response:

EPA has clarified the applicability language as suggested by the commenter.

Comment:

Several commenters (OAR-2002-0056-2922, -2634, -2718) identified a number of instances where the definitions do not reflect the proposed regulatory provisions. For example, the provisions for regulation of "oil-fired" units apply to any unit combusting oil. Because some coal-fired units combust oil for start-up, the definitions of "coal-fired" and "oil-fired" should be revised to make clear that units that combust both coal and oil are not "oil-fired," and that any unit regulated as a coal-fired unit is not subject to the "oil-fired" unit limits. Those revisions

would be consistent with EPA's statements in the preamble regarding applicability.

Several commenters (OAR-2002-0056-2634, -2718, -2922) stated that under the proposed rule, units combusting "natural gas at greater than or equal to 98 percent" of the unit's annual fuel consumption are not affected units under this proposal. Because other provisions in the rule state that they apply to "coal-fired" units, the definition of "coal-fired" should be revised to reflect the 98 percent or more exclusion for combustion of natural gas.

Response:

EPA has clarified the definitions. It was EPA's intention that the definition of a "coal-fired" boiler would be the governing definition. That is, if a unit burned coal, in any amount, then it would be classified as a "coal-fired" boiler and subject to the Hg regulation. A unit that is designed to burn oil is more likely to be able physically and actually to combust natural gas interchangeably than is a unit designed to burn coal. Units continue to be exempt from the emission limits during periods of startup, shutdown, and malfunction. Therefore, coal-fired units that combust natural gas during such periods would, during these periods, be exempt from the regulations.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2922) noted that the rule would include several exclusions related to combustion of "natural gas," which is not defined. Section 63.10042 should be revised to include a definition of natural gas. EPA should also consider whether combustion of synthetic gaseous fuels that are not derived from coal (e.g., digester gas and landfill gas) also should be eligible for the 98 percent exclusion. The commenters believe that they should be.

Response:

EPA will add the definition of natural gas as suggested by the commenters. However, the other synthetic gases noted by the commenters are not "fossil fuels" under the definitions in 40 CFR 60.41a and, therefore, units firing these fuels would not be subject to this regulation unless such firing was in combination with the firing of coal.

Comment:

One commenter (OAR-2002-0056-3449) stated that a definition of startup should be added to the rule.

Response:

"Startup" is already defined in the General Provisions at 40 CFR 60.2.

2.1.2 Industrial Boilers

Comment:

One commenter (OAR-2002-0056-2331) agreed with EPA's position that the rule should apply to only electric utility steam generating facilities (EGU). The commenter added that non-EGU should not be included under the proposed rule. The commenter also stated that Hg emissions from industrial boilers are insignificant in comparison with those from EGU.

Response:

EPA concurs that industrial boilers should not be included in the same source category as electric utility steam generating units.

2.1.3 Cogeneration Units

Comment:

One commenter (OAR-2002-0056-2277) believed that consistent with Acid Rain regulations, the proposed definition of "electric utility steam generating unit" seems intended to exclude units that are primarily designed to provide power to industrial facilities. The commenter believed the definition seems intended to create two categories that are regulated, typical electricity generating utilities, and co-generation units that supply more than one-third of its potential electric output capacity and more than 25 megawatts-electric (MWe) output to any utility power distribution system for sale. The commenter noted that, however, as written, the first category seems overly broad and could be read to include the industrial units that are intentionally excluded from the second category (those that supply less than one-third of the units potential electric output capacity or less than 25 MWe output to any utility power distribution system for sale). The commenter further noted that, as written, the second category does not create an exemption from the first category, although it seems intended to create this exemption. To clarify that the regulation applies only to units that produce more than one-third of their power for sale, the commenter suggested the definition be changed as follows:

> Electric utility steam generating unit means any fossil fuel-fired combustion unit of more than 25 MWe that serves a generator that produces more than one third of its potential electric output capacity and more than 25 MWe of its electricity for sale. A unit that co-generates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also considered an electric utility steam generating unit.

The commenter noted that, alternately the regulation could be changed as follows to show that the second category exempts units from the first category:

> Electric utility steam generating unit means any fossil fuel-fired combustion unit of more

than 25 MWe that serves a. generator that produces electricity far sale. A unit that co-generates steam and electricity and supplies less than one-third of its potential electric output capacity or less than 25 MWe output to any utility power distribution systems for sale is not an electric utility steam generating unit.

Response:

EPA believes that the definition provided in revised subpart Da clearly defines two categories of new sources – utility units and non-utility units (which could include industrial boilers, combustion turbines, etc.). That is, a joint condition must be met in order to be classified as a Utility Unit – the unit must provide more than one-third of its potential electric output capacity ***and*** *more than 25 MWe electrical output to any utility power distribution system for sale. Further, the boiler itself must be capable of combusting more than 73 MW (250 million Btu/hr) heat input (which equates to 25 MWe on an output basis). The Agency's historical interpretation of the subpart Da definition has been that a boiler meeting the capacity definition (i.e., greater than 250 million Btu/hr) but connected to an electrical generator with a generation capacity of 25 MWe or less would still be classified as an "electric utility steam generating unit" under subpart Da. However, one or more new boilers with heat input capacities less than 250 million Btu/hr connected to an electrical generator with a generation capacity of greater than 25 MWe would not be considered Utility Units because they individually do not meet the definition (they would be considered industrial boilers). EPA acknowledges that there are differences in definitions between the NSPS program and the Acid Rain and other trading programs (e.g., CAIR) that result from the underlying statutory mandates.*

With regard to the amount of power sold to the grid and the "trigger" beyond which a unit is considered a Utility Unit for the purposes of this rulemaking, again there are definitional differences that have developed from the statutory mandates. EPA believes that new sources have the foreknowledge of the rules in effect and, thus, should be expected to be able to determine up-front whether they want to be considered a Utility Unit or an industrial boiler (i.e., do they plan on selling, or is it likely that they will sell, more than one-third of their power in the future). Therefore, EPA considers a new cogeneration unit to be subject to the subpart Da Hg emission limit if it ever exceeds the definitional threshold. Existing units, discussed further elsewhere in this document, are brought into the program at its inception rather than at their start-up. Therefore, EPA is using an annual average threshold for existing units, noting that if the threshold is ever met for a given year, then the unit will be considered a Utility Unit from there on out.

Comment:

Several commenters (OAR-2002-0056-2085, -2206, -2906, -2922, -3525) recommended that the final rule allow cogeneration (or combined heat and power; CHP) units above 25 MWe to supply up to 25 MWe electrical output or up to one-third of their potential electrical output capacity to a utility power distribution system for sale on a net annual basis as is done in the Acid Rain program. This would likely minimize the possibility of non-utility units being classified as utility units based upon unique situations of relatively short duration or of unrepresentative operating history (e.g., if power was generally used exclusively at the plant at

which it was generated, but was sold to the grid when the production facility was down for maintenance). In the event that a unit were classified as a Utility Unit and had to meet a more stringent standard, the EPA should provide a reasonable period of time for the unit to come into compliance. Two commenters (OAR-2002-0056-2206, -2906) stated that this requirement stands in contrast to EPA's proposed CAIR, where the definition for a Utility Unit is based on a historical annual average (69 FR 4610). The commenter stated that to prevent these undesirable consequences, and to prevent conflicts and confusion with the definition of a Utility Unit in the CAIR, EPA should base the Utility Unit definition on a net annualized average and not "during any portion of the year."

One commenter (OAR-2002-0056-2085) stated that EPA created a new opportunity for misunderstanding by proposing in the rule that a cogeneration unit that meets the definition of a Utility Unit during any portion of a year would be subject to the proposed rule (69 Fed. Reg. 4657). The commenter believed that EPA should not adopt its proposed approach to cogeneration units that may operate as "electric utility steam generation units" on a short-term or temporary basis. According to the commenter, the proposed approach will create complicated and unnecessary issues in implementation. The commenter asked is a "year" a calendar year or a 12-month rolling average? The commenter also asked how long does a cogeneration unit need to meet the "electric utility steam generation unit" definition to qualify - one day, one hour, or one minute? The commenter believed that EPA will not gain a material improvement in environmental conditions by creating these implementation problems (caused by a unit being classified as an "electric utility steam generation unit" on a short-term or temporary basis). According to the commenter, the Industrial Boiler MACT rule has Hg limits for boilers of the size involved here (40 CFR Part 63 Subpart DDDDD, Table 1). The commenter noted that for coal-fired electric utility units, the principal environmental benefit is the Hg limit. The commenter believed these cogeneration units should be subject only to the Industrial Boiler MACT (40 CFR Part 63 Subpart DDDDD).

Three commenters (OAR-2002-0056-2206, -2906, -3525) stated that in the preamble, EPA, absent rationale, states that any CHP unit that meets the definition of a Utility Unit during any portion of the year would become subject to the rule. The commenters stated that requiring a CHP unit to stay below the Utility Unit definition on an instantaneous basis provides a disincentive for facilities to invest in new CHP capacity or to maximize the output and efficiency of their current CHP and energy-producing network of units. The commenters encouraged EPA to confirm that for purposes of its proposed definitions of "electric utility steam generating unit" and "cogeneration unit," all sales of electricity will be measured on a "net" annual basis, as is done in the Acid Rain program. The commenters stated that in determining that "net" basis, EPA's accounting should take account of the specific situation of major facilities with a number of cogeneration units. The commenters stated that at such plants, some units may be over the size threshold, while others may be below it. Yet, according to the commenters, the electricity from all those units will be pooled before it is either used in the plant or sold to the grid. In that case, the commenters believed EPA's accounting rules should provide for determining when the threshold conditions have been met by looking at all the electricity generated by all the cogeneration units, whether they were subject to the SIP call or not. The commenters asserted that no other approach would be administratively feasible. In addition, the commenters pointed

out that, in some cases, contractual arrangements may exist between the cogeneration facility and the local electric utility wherein all generated power is considered sold to the utility and all electricity used on the site is purchased from the utility. According to the commenters, in reality, only a small portion of the generated power really enters the grid from the cogeneration facility, and only that "net" sales of power should be considered when determining applicability with the EGU definition. Subject to these qualifications, the commenters supported the cogeneration unit threshold being used for consideration as an EGU, specifically, a unit serving a generator with a nameplate capacity of greater than 25 MW and supplying more than one-third of its potential electric output capacity and more than 25 MW to any utility power distribution system for sale. The commenters stated however, it would provide additional clarity and prevent confusion if it was specifically stated that units associated with generators of 25 MWe capacity or less were not affected sources under this subpart; and any cogeneration units not supplying both more than one-third of their potential electric output capacity and more than 25 MWe to any utility power distribution system for sale were not affected sources under this subpart. The commenters recommended that EPA include this additional clarifying language in the final rule.

Two commenters (OAR-2002-0056-2206, -2906) stated that requiring a cogeneration unit to stay below the Utility Unit definition on an instantaneous basis would create a large disincentive for facilities to invest in new CHP capacity, or to maximize the output and efficiency of their current cogeneration and energy-producing network of units. According to the commenters, cogeneration units are inherently more efficient than traditional Utility Units (in many cases twice as efficient), and often provide distributed key power to the grid during transient or short-term periods of peak power demand. The commenters stated that in order to prevent being included within the Utility Unit definition, many cogeneration units will likely establish tight restrictions on exporting excess power to the grid, or eliminate export all together. According to the commenters, this would have the perverse effect of reduced cogeneration unit power output, reduced overall grid efficiency and reduced industrial steam and electricity generation efficiency.

Response:

EPA believes that its historic interpretation of the subpart Da definition of an "electric utility steam generating unit" has been that meeting the criteria (i.e., more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale) at any time subjects the source to subsequent compliance with the appropriate standard. Subpart Da is applicable to ***each*** *new electric utility steam generating unit otherwise meeting the definition. Thus, there is no more basis for considering a group of cogeneration units for the purpose of determining applicability with the rule than there is currently for considering a group of non-cogeneration boilers.*

Comment:

One commenter (OAR-2002-0056-3525) stated that in both the proposed rule and preamble (69 FR 4696 and 69 FR 4762), EPA applies the 18 CFR 292.205 efficiency methodology to cogeneration facilities (implied to be limited to solid-fuel fired facilities because

gas-fired units are not included in the rule applicability). The commenter submitted that this proposed emission rate calculation for cogeneration units appears to unfairly penalize them for sales of any electric power less than the full generation capacity. According to the commenter, such a penalty is contrary to the Bush Administration's stated intent to advance the application of cogeneration facilities and thereby improve the nation's energy efficiency and achieve greenhouse gas emission intensity reductions. The commenter strongly encouraged EPA to reconsider this approach. The commenter believed a much more equitable and workable approach would be to provide cogeneration facilities with the ability to use input-based emission limits and calculations. The commenter stated that in that way, the boiler, fuels, and emissions controls will determine compliance without the apparent emission rate being unfairly skewed by the portion of electricity sold to the grid. According to the commenter, this method also follows from past EPA practice in establishing emissions standards. The commenter submitted that EPA should establish emissions standards that encourage installation and operation of highly efficient cogeneration facilities, and recognize their inherent variability in design and operating profiles versus typical single use electric utility units.

Response:

The approach EPA has taken with regard to crediting the steam generated beyond that necessary to generate electric power in a cogeneration system is consistent with that taken during the earlier revision of the subpart Da NO_x emission limits. We believe that consistency is appropriate for this application.

Comment:

Two commenters (OAR-2002-0056-2906, -3525) supported EPA's decision not to set emission limits for utility units that burn 98 percent or more of natural gas. The commenters noted that historically, EPA has not drawn a distinction among natural gas and other refinery or process gases, but rather has determined to define and regulate them as simply "gaseous fuels." The commenters noted that although most commercial gas-fired utility units burn natural gas, many CHP units located at petroleum refineries or petrochemical facilities also burn some amount of refinery fuel gas or other process gas that is being produced and consumed onsite for energy production. Commenter OAR-2002-0056-2906 noted that in the Industrial Boiler MACT, EPA included not only natural gas but also process gas and refinery gas in the same subcategory. In other words, in that rule EPA did not draw a distinction among natural gas and other refinery or process gases, but rather defined and regulated them as simply "gaseous fuel." The commenter stated that this same issue exists for Utility Units under the proposed rule, and in particular cogeneration units that meet EPA's definition of a Utility Unit. The commenter believed that most readers would conclude that this rule and its emission limits do not apply to CHP-type or other utility units that burn 98 percent or more of natural gas, including other gaseous fuels. The commenters stated that, however, it would help clarify matters if the rule specifically stated that this exemption applies not just to natural gas, but also to other gaseous fuels such as process and refinery gases, as well as other non-residual fuel oil fuels, in keeping with EPA's approach in the Industrial Boiler MACT.

Response:

EPA believes that a reasonable interpretation of its exclusion provision for natural gas-fired units would include other gaseous fossil fuels. However, EPA has clarified in the final rule to indicate that only units that combust coal, in any amount, or any coal-derived fuel are subject to the rule.

2.1.4 Combined Heat and Power Units

Comment:

Several commenters (OAR-2002-0056-2066, -2206, -2833, -3530) stated that the final NSPS utility rule should not extend its mandates to either current or future CHP systems. The commenters stated that in virtually all cases, CHP units are a source of highly efficient power with correspondingly low emissions. According to the commenters, because cogeneration units are generally twice as efficient (i.e.; more output per unit of input) as non-CHP Utility Units, they consume less coal and oil, and have significantly less emissions than fossil-fuel burning non-CHP Utility Units. The commenters asserted that, for this reason, encouraging CHP units should be part of EPA's strategy toward reducing harmful emissions from the electricity generating sector. The commenters stated that the Agency should not, therefore, seek to impose additional regulation on these units. The commenters added that hundreds of industrial facilities depend on the economic efficiencies of CHP. The commenters stated that in fact, the President's National Energy Policy recommends the increased use of CHP systems to improve energy efficiency and decrease air emissions (See National Energy Policy, Report of the National Energy Policy Development Group, May 2001, pp. 4-11 and 6-18). The commenters also stated that however, industrial units should be given the opportunity to voluntarily opt-in to the benefits of the cap-and-trade program. The commenters stated that any opt-in provision should be drafted to encourage participation and recognize cost-effective emission reductions tailored to the unique attributes of manufacturing facilities.

Two commenters (OAR-2002-0056-2066, -2206) stated that CHP units currently represent only about 3 percent of the electric generating capacity covered by Agency's proposal. According to the commenters, CHP units are generally twice as efficient when compared to their utility counterparts, and about two-thirds of all CHP units burn natural gas and have extremely low NO_x emission rates. The commenter stated that although individual CHP emission rates will vary, the average gas-fired CHP emission rates are only 15 to 25 percent of that emitted by a typical utility. The commenter added that even CHP units using coal or oil as a fuel source are still much more efficient than a utility using the same fuels. The commenter further stated that CHP units are usually only a small part of a much larger industrial facility or complex. According to commenter OAR-2002-0056-2206, including CHP units in this rule may require them to install flue gas desulfurization (FGD) or selective catalytic reduction (SCR) control technology by 2010 or purchase credits. The commenter stated that these costs will be a significant disincentive to building these environmentally superior forms of electricity generation and could significantly impair continued reliance on this type of environmentally wise technology. The commenter asserted that including these units into this rulemaking would layer

another set of regulations on the entire facility, thus further complicating on-going compliance efforts, and, because there are relatively little emissions coming from such units, not significantly reduce the amount of Hg. The commenter added that EPA is proposing that compliance with its new standards will be based on emissions attributable to combustion for electricity generation, and not from steam production (See e.g., 69 FR at 4,668 and 4,696). For these reasons, the commenters believed that CHP units should be exempted from inclusion in this rulemaking. According to the commenters, inclusion of traditional CHP facilities would provide negligible environment benefit while discouraging application of these ultra-efficient power and steam generators both now and in the future.

Response:

EPA sees no reason to exclude cogeneration or CHP units that otherwise meet the definition of "electric utility steam generating unit" from the final rule, as units meeting the definition would, like other similarly sized but non-cogeneration units, be emitters of Hg.

2.1.3 Other

Comment:

One commenter (OAR-2002-0056-2835) stated that for any regulatory program for Hg and Ni emissions, EPA should clarify that compliance with the regulatory requirements qualifies as a pollution control project. The commenter stated that regardless of whether EPA implements a regulatory program under CAA section 112(d), section 112(n)(1)(A), or section 111, the regulation should provide that projects and/or activities undertaken by electric utilities to comply with the obligations of a Hg regulatory program do not trigger the requirements of New Source Review (NSR) or Prevention of Significant Deterioration (PSD). The commenter further stated that as a matter of policy, an affected source should not trigger additional regulatory requirements when undertaking efforts to comply with a set of new regulations, particularly where the new rules lead to reductions in HAP.

The commenter noted that the proposed emission guidelines for oil-fired units already include a provision in Section 60.4010(b) which states that "[p]hysical or operational changes made to an existing electric utility steam generating unit solely to comply with an emission guideline are not considered a modification or reconstruction and would not subject an existing electric utility steam generating unit to the requirements of subpart Da (see Section 60.40a of subpart Da)." The commenter recommended that this provision be expanded to include the requirements imposed by the NSR and PSD programs. Furthermore, the commenter urged EPA to include this expanded provision in any regulatory program for all electric utilities (i.e., the MACT standard or a cap-and-trade program). The commenter stated that by making the rule explicit that such projects would not trigger the NSR and PSD programs, EPA avoids the situation where State permitting agencies have to second guess whether implementation projects and activities are indeed pollution control projects.

Response:

NSR and PSD are only triggered through emission increases. Compliance with the promulgated rule would not result in emission increases and, thus, would not trigger NSR or PSD.

2.2 SUBCATEGORIZATION

The proposed NSPS includes Hg emission limits for new coal-fired units subcategorized by coal rank (bituminous, subbituminous, lignite, waste coal, integrated gasification combined cycle [IGCC]). The rationale for subcategorization under section 111 is the same as was described in the January 30, 2004, proposed section 112 standards. Therefore, many commenters only addressed subcategorization in the context of section 112; it is presumed that their comments, when not otherwise explicitly stated, also pertain to the proposed section 111 standards.

2.2.1 Support for Subcategorization

Comment:

One commenter (OAR-2002-0056-2915) pointed out that under CAA section 111, EPA has previously subcategorized coal-fired utility units based on the sulfur levels in the coals they burn. The commenter noted that this subcategorization approach was approved by the U.S. Court of Appeals for the District of Columbia Circuit in Sierra Club v. Costle, 657 F.2d 298 (D.C. Cir. 1981). The commenter stated that in approving EPA's NSPS regulations, the Court recognized that CAA section 111 allowed EPA "to distinguish among classes, types and sizes within categories." The commenter noted that the Court explained that "[o]n the basis of this language alone, it would seem presumptively reasonable for EPA to set different...standards for utility plants that burn coal of varying sulfur content." Thus, the Court found that EPA could create subcategories based on the type of fuel an EGU burns.

One commenter (OAR-2002-0056-2862) stated that in establishing a new source NSPS for Hg, EPA should subcategorize coal-fired power plants based on the rank of coal fired. The commenter stated that pursuant to CAA section 111(b)(2), EPA has the authority to distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing NSPS standards. (42 U.S.C. section 7411(2)) The commenter stated that it supports EPA's proposed subcategorization of coal-fired power plants based on coal rank and also referred to the Circuit Court case (Sierra Club v. Costle, 657 F.2d 298 (D.C. Cir. 1981)).

Several commenters (OAR-2002-0056-2067, -2161, -2247, -2264, -2332, -2365, -2375, -2634, -2721, -2725, -2835, -2891, -2897, -2898, -2900, -2907, -2911, -2915, -2918, -2948, -3198, -3200, -3398, -3440, -3469, -3514, -3537, -3539, -4139, -4191) supported EPA's use of subcategories. Two commenters (OAR-2002-0056-2375, -2918) supported EPA's decision to subcategorize bituminous, subbituminous, and lignite-burning affected units and stated that EPA's subcategorization based on coal rank is proper under section 111, which gives EPA broad

authority to subcategorize as it deems appropriate. The commenter also stated that the CAA, as interpreted by the D.C. circuit and the legislative history, make clear that EPA has broad authority to distinguish among classes, types, and sizes of sources to account for differences in the effectiveness of control technology. One commenter (OAR-2002-0056-2375) stated that EPA's approach to the subcategorization of electric utility steam generating units is generally appropriate and consistent with the CAA and believes that subcategorization of coal-fired and oil-fired units into two subcategories is warranted based on their distinct emissions profiles and their typical uses as base-load and peaking units, respectively. The commenter also supported EPA's proposal to subcategorize coal-fired units by coal rank, in part, to account for the significant impact coal rank can have on overall plant design, the design process and the operation of pollution controls.

According to several commenters (OAR-2002-0056-2067, -2365, -2375, -2725, -2898, -3198, -3514), subcategorization by coal rank is amply supported by the differences in Hg speciation that in turn impact the effectiveness of control technology. One commenter (OAR-2002-0056-2891) notes that cooperatives are users of all three general coal ranks and, in relation to the rest of the industry, are heavy users of subbituminous and lignite coals. The commenter stated that because it is much more difficult and expensive to reduce Hg emissions from these when compared to eastern bituminous coal, a single standard for Hg emission limits for all coal-fired power plants would be impossible, as a practical matter, for some lignite and subbituminous coal burning plants to meet. The commenter believed that it is imperative that in the final rule, the use of any specific coal type or rank must not be advantaged or disadvantaged.

One commenter (OAR-2002-0056-2897) stated that concerns that subcategorization causes an increase in allowable Hg emissions are unjustified in that under a cap-and-trade system, the emissions cannot exceed the cap, and under a MACT system the average floor effectively sets the emission level. The commenter believed that subcategorization does not necessarily raise emissions but merely ensures that the compliance burden is evenly distributed. The commenter also stated that concerns that subcategorization may result in more complex permitting are overstated and can be resolved. The commenter indicated that permitting is a relatively minor issue compared with the disruption to the nation's energy system and fuel switching, including switching to gas, that will occur if bituminous and subbituminous coals are not subcategorized separately.

One commenter (OAR-2002-0056-2375) supported EPA's subcategorization of IGCC units based on the distinct processes that such units employ (i.e., they are the only units that do not combust coal in the unit during operation).

One commenter (OAR-2002-0056-2948) supported EPA's decision to subcategorize electric utility steam generating units and stated that EPA should place oil-fired units in a different category than coal-fired units because emissions from those plants differ markedly.

One commenter (OAR-2002-0056-2721) agreed with EPA's proposed five subcategories - four based on coal ranks and one for process type - and disagreed with the option to combine subbituminous with bituminous coals for the purposes of Hg regulations. The commenter did

not agree that a five-category program places a burden on the Utility Unit for tracking burn rates from various coal sources on a monthly or annual basis. The commenter asserted the practical implications of this co-categorization would be significant. The commenter stated that the differences in the Hg emission levels on subbituminous and bituminous coals are great and have been well documented and published in the ICR data. The commenter noted that these coals are currently blended for sulfur compliance. The commenter stated that because of the significant higher sulfur content in the bituminous coal, the reverse scenario of blending bituminous coal with subbituminous coal for Hg compliance would be detrimental to the SO_2 compliance of the facility.

Several commenters (OAR-2002-0056-2260, -2560, -2725, -3440) supported EPA's proposal to use subcategories in setting emissions limits and providing allocations to adequately address differences in abilities to control Hg based on coal chemistry that varies with coal rank. One commenter (OAR-2002-0056-2560) stated that their coal-fired facilities have different boiler configurations and fuel firing abilities, and that this is typical for the industry. The commenter further stated that a key consideration in Hg removal from coal is the presence or lack of halogens. The commenter supported subcategorization in that it recognizes the technological challenges presented by the lack of halogens in Powder River Basin (PRB) subbituminous coals.

One commenter (OAR-2002-0056-2725) believes that subcategorization should include at least three categories: lignite, subbituminous, and bituminous coals. The commenter stated all these coal ranks behave differently when burned, releasing significantly different levels of Hg that may require different controls. The commenter adds that Hg control costs for lignite and subbituminous coals may be higher at plants that already have particulate matter (PM) and sulfur dioxide (SO_2) controls than the control costs for plants burning bituminous coal. The commenter stated that any regulation of Hg that includes a one-size-fits-all standard would unfair. The commenter stated that lignite and subbituminous coals are fundamentally different from bituminous coal.

Several commenters (OAR-2002-0056-2830, -3543, -3406) supported the separate treatment of lignite through the subcategorization process.

One commenter (OAR-2002-0056-3208) believed it is important for EPA to recognize the relative disadvantage at which it now places PRB subbituminous coal due to the preponderance of elemental Hg in its content. The commenter submits that PRB coal now will be placed at risk in contravention of previous environmental policies that encouraged its use. According to the commenter, these factors should motivate EPA to recognize the need for subcategorization of coals in determining MACT for Hg removal.

In supporting EPA's decision to create separate subcategories for bituminous and subbituminous coals, one commenter (OAR-2002-0056-2897) stated that bituminous coals are more likely to be used in a plant equipped with wet flue gas desulfurization (wet FGD) for SO_2 control and selective catalytic reduction (SCR) for nitrogen oxides (NO_x) control and are, therefore, more likely to benefit from "co-benefit" capture in these systems, whereas a

subbituminous coal is more likely to be burned in a plant with a dry scrubber, which has shown no quantifiable Hg capture in testing to date. The commenter also stated that supra fuel switching is not a viable solution and failing to subcategorize between bituminous and subbituminous would create regional disparities.

Several commenters (OAR-2002-0056-1969, -2161, -2535, -2661, -2843, -2867, -2891, -2897, -3539) supported separate subcategories stating that there are significant differences between the two coals, subsequent speciation of the Hg in the flue gases, and differences in achievable emission reductions. One commenter (OAR-2002-0056-2661) stated that if coal ranks were combined into a single category, rural electric consumers would be negatively impacted. The commenter stated that if a single standard for Hg emission limits were set for all coal-fired power plants, based on bituminous rank coals, it would be impossible, as a practical matter, for some lignite and subbituminous coal burning plants to meet that standard. One commenter (OAR-2002-0056-2891) stated that cooperatives are users of all three general coal ranks and, in relation to the rest of the industry, are heavy users of subbituminous and lignite coals and would be disadvantaged under a single emission limit.

One commenter (OAR-2002-0056-2948) stated that EPA should subcategorize units based on differences between coal ranks. The commenter did not believe, however, that EPA should place units burning coals of more than one rank in a separate subcategory because large differences exist in the way plants burn coals of more than one rank.

One commenter (OAR-2002-0056-2067) agreed with EPA that there is no demonstrated justification to create a separate category for circulating fluidized bed (CFB) units.

Response:

EPA concurs with the commenters.

2.2.2 No Subcategorization

Comment:

Many commenters (OAR-2002-0056-2575, -2823, -2878, -2920, -3459) doubt the legality of EPA's use of subcategorization by coal rank. One commenter (OAR-2002-0056-2920) stated that EPA's proposal to subcategorize by coal rank is unlawful, arbitrary, and capricious for the following reasons:

(1) EPA provides no reason to believe that just because some plants are located near mine mouths (e.g., lignite plants), they are of a different class, type, or size than other units;

(2) EPA argues that the characteristics of the coal rank to be burned was the driving factor in how a unit was designed, but does not say what those design differences are and does not claim that any such differences are so great that plants designed to burn different

ranks of coal are different classes, types, or sizes of a unit;

(3) EPA admits that many plants burn two or more different ranks of coal;

(4) EPA admits that its basis for subcategorization was to ensure that standards are achievable for all sources through the use of certain technologies. According to the commenter, this argument has been found unlawful (Cement Kiln Recycling Coalition v. EPA);

(5) EPA appears not to have seriously considered alternative subcategorization approaches or no subcategorization.

One commenter (OAR-2002-0056-2878) stated that EPA fails to provide any technical rationale to justify why coal rank should define the allowable emissions a unit can emit when technology is available that enables all plants to meet high levels of Hg control regardless of coal rank. According to the commenter, EPA's rationale is based on a misguided claim that boilers are specifically designed for a specific rank of fuel. Yet, according to the commenter, units burn more than one rank of coal in the same boiler. In support, the commenter cited the Stanton study which showed that high levels of Hg reduction can be achieved with currently available technology, regardless of coal rank. According to the commenter, the Stanton study was used as the basis for Iowa's recent permit for a new unit burning subbituminous coal from the PRB that requires 83 percent reduction using activated carbon injection (ACI) or other sorbent injection.

According to one commenter (OAR-2002-0056-2823), 11 State Attorneys General contend that EPA's proposed subcategorization by coal rank is unlawful because:

(1) EPA applied the scheme inconsistently (i.e., EPA cannot insist that emission standards be set for specific subcategories and then reject standards that are so tailored because they are not appropriate for every unit in the category as a whole);

(2) EPA's scheme does not accurately reflect industry practices as it applies to the subcategorization scheme because there are units that burn more than one rank of coal; and

(3) The proposed scheme does not serve to protect health and the environment in that EPA admits that it elected to subcategorize by coal rank so as to produce a standards achievable by all units, ensuring that units continue to operate rather than on protecting human health and the environment.

One commenter (OAR-2002-0056-2575) argued that subcategorization can only be done on three criteria: class, type, and size of sources and the factor that coal rank is one of the characteristics of a coal-fired boiler does not mean it can be used for subcategorization. The commenter stated that EPA's reliance on coal rank is misplaced because many coal-fired units blend or fire two or more ranks of coal in the same boiler and EPA itself states that coal blending is possible and not uncommon. The commenter stated that EPA also claims (with no support)

that fuel switching would require significant modification or retooling of a unit. The commenter cited case law to support its contention that EPA's subcategorization is not permitted. The commenter stated that EPA's justification for rejecting a no subcategorization option is factually and legally indefensible. That is, EPA based its subcategorization on two principles:

(1) plants were largely designed based on coal rank to be burned and fuel switching would be problematic, and

(2) the type of coal rank to be burned is based on economic issues, including availability withing the area.

The commenter stated that, as stated above, reliance on coal rank is factually wrong and fuel switching is a common practice.

According to one commenter (OAR-2002-0056-3459), EPA's proposed subcategories are contrary to law, without rational basis, arbitrary and capricious, and an abuse of discretion. The commenter stated that EPA proposes subcategorization by coal rank, based on the arguments that combustion technologies are coal-rank specific and that many utilities are dependent on particular mines and, therefore, particular ranks of coal. According to the commenter, these arguments are not supported by the facts:

(1) Utilities regularly burn more than one rank of coal together and there is no significant technical difference in the boilers receiving various ranks of coal.

(2) EPA's reliance on American Society for Testing and Materials (ASTM) methods to determine coal rank is so technically problematic that it erodes EPA's rationale for subcategorization by coal rank. Coal rank is not an easily discernible and always clear characteristic of coal and EPA itself acknowledges some overlap.

(3) Individual mines can produce different ranks of coal. EPA's justification that many utilities are dependent on particular mines and therefore particular ranks of coal is not supported.

(4) EPA acknowledges that coals of varying ranks have similar combustion and handling properties, and operators have learned to handle these blends but then ignores it.

(5) EPA's assumptions also differ from real world experience where many units switched to low-sulfur coal to satisfy the acid rain program requirements, demonstrating that units are capable of burning a mix of coal ranks.

(6) Even if different ranks do have different properties, coal treatment technology may allow one coal rank to act in ways that make it more like a coal of a different rank. EPA acknowledges that a key consideration in subcategorization decisions is whether different units have differences in the feasibility in the application of control technology. However, available evidence shows that units burning different ranks of coal are equally

amenable to Hg pollution controls. Both high and low rank coals (such as bituminous and subbituminous) coal can be controlled by the same control technology

(7) Although EPA has only spurious rationale for subcategorization of existing units; there is no rationale for new units. These can be designed to provide optimum performance when firing all coal ranks.

Response:

EPA continues to believe that it has the statutory authority to subcategorize based on coal rank and process type, as appropriate for a given standard. As initially structured, subpart Da subcategorized based on the sulfur content of the coal (essentially based on coal rank) for SO_2 emission limits and based on coal rank for NO_x emission limits. This approach was selected because of the differences in the relative ability of the respective control technologies to effect emission reductions on the various coal ranks. Although EPA has subsequently changed the format of the NO_x emission limits and has recently proposed to establish common SO_2 emission limits regardless of coal rank (70 FR 9706), we believe that the conditions existing at proposal of the previous standards (e.g., the inability of the technologies to control SO_2 and NO_x equally from all coal ranks) equally apply now for Hg and justify the use of subcategorization by coal rank for the Hg emission limits. This does not indicate, however, that at some point in the future, the performance of control technologies on Hg emissions will not advance to the point that the rank of coal being fired is irrelevant to the level of Hg control achieved (similar to the point reached by controls for SO_2 and NO_x emissions). At that time, EPA may adjust the approach to Hg controls appropriately.

Comment:

Many commenters (OAR-2002-0056-1471, -1611, -1682, -1686, -1687, -1773, -1861, -2108, -2160, -2243, -2334, -2415, -2441, -2819, -2833, -2878, -2887, -2889, -2924, -3199, -3435, -3437, -3440, -3449) opposed the use of subcategories based on fuel types. One commenter (OAR-2002-0056-3199) recommended that EPA establish fuel-neutral limits that account for the high variability in coal, combustion processes, and control system performance under different types of firing conditions. Several commenters (OAR-2002-0056-1471, -1611, -1773, -1861, -2108) believe that subcategorization by coal rank is not warranted or is otherwise questionable because a unit can burn bituminous or subbituminous coal with no change to the boiler. They argued that a fuel-neutral rule would provide an incentive for plants to blend the two ranks of coal and point to the industrial boiler MACT which was fuel neutral. These commenters stated that subcategorization by coal rank simply guarantees the continuing use of Hg-heavy fuel. In opposing subcategorization, two commenters (OAR-2002-0056-2243, -2878) stated that the percent removal requirement should be the same for all fuel ranks and unit configurations. One commenter (OAR-2002-0056-2878) recommended a single performance standard to reduce emissions by 90 percent in 2007 and stated that this can be achieved by ACI with an electrostatic precipitator (ESP) and a retrofit fabric filter or a fabric filter alone.

Several commenters (OAR-2002-0056-1682, -1686, -1687, -2108) oppose

subcategorization by coal rank because plants burning western, subbituminous, or lignite coal remain uncontrolled while plants burning eastern bituminous coal must have one or more controls. The commenters stated that this is inconsistent with the CAA's fuel neutrality and harms the economies of States with eastern coal. According to the commenters, Illinois has seen a 25 percent increase in Hg emissions due to a switch to subbituminous coals. They stated that this impact has not been reflected in the EPA analyses. One commenter (OAR-2002-0056-2160) stated that Illinois, Indiana, Ohio, and West Virginia oppose subcategorization by coal rank and prefer limits that are fuel neutral. The commenter stated that the more stringent limits for bituminous coal will result in fuel switching with severe economic impacts on States that produce bituminous coal and negligible emission reductions due to switching to subbituminous coal as the low cost compliance strategy for Hg. One commenter (OAR-2002-0056-2819) supported a single fuel-neutral limit that would not be any less stringent than the rules proposed by New Jersey and promulgated by Massachusetts. According to the commenter, compliance can be achieved through currently available technologies: for a cyclone boiler, SCR can be used in conjunction with FGD or ACI and a particulate control device, and, for a tangential boiler, compliance can be achieved through an appropriate PM control device that collects fly ash if needed or by ACI with a particulate control device when fly ash re-injection systems are used. Two commenters (OAR-2002-0056-2924, -3449) oppose subcategorization on the grounds that the higher limit for subbituminous coal could encourage operators to switch and blend fuels resulting in an increase in Hg emissions. One commenter (OAR-2002-0056-2924) stated that as a result, they would continue to be impacted by Hg emissions from other areas and that differentiation should be based on the type of unit (which would not discriminate against fuel type), not the rank of coal.

One commenter (OAR-2002-0056-3449) stated that subbituminous coals or blends of subbituminous and bituminous coals can frequently be burned in units previously burning only bituminous coal without extensive retrofit. According to this commenter, combustion of waste coal or anthracite coals also results in similar emissions; thus, separate limits for bituminous, subbituminous, and waste coal is questionable. One commenter (OAR-2002-0056-2889) stated that if EPA had used a sufficiently long averaging time (which it did not attempt to address), it would obviate the need to consider variability of coal Hg content, allowing a coal-neutral rule. The commenter stated that another difficulty with the subcategorization scheme is the inaccuracy typically encountered in determining the amount of different ranks of coal in a blend, which is typically done in a bulldozer. One commenter (OAR-2002-0056-2887) stated that practical reasons for limiting the number of subcategories is the reduced regulatory burden and increased plant flexibility in fuel procurement and management strategies. One commenter (OAR-2002-0056-2819) stated that EPA's analyses supporting subcategorization are severely flawed because of the limited amount of stack test data collected and analyzed to date. The commenter stated that as more data is collected (primarily at the State level), it is evident that factors other than coal rank are more important in determining Hg speciation and the ability of commercially available control technologies to reduce emissions from coal-fired boilers. According to the commenter, important factors that affect Hg speciation and control effectiveness include: the combustion efficiency of the utility boiler, and the combination of control. One commenter (OAR-2002-0056-3437) stated that subcategorization creates a competitive advantage for western coal that is not justified and is inconsistent with other Federal

programs such as the NO_x SIP Call and the proposed Clean Air Interstate Rule (CAIR; originally titled at proposal the Interstate Air Quality Rule, IAQR), which are fuel neutral. One commenter (OAR-2002-0056-3435) stated that the variability of the Hg and chlorine (Cl) content of coal within a rank, the ability of a unit to burn more than one rank of coal, and the magnitude of the difference in emission limits diminishes the merit of subcategorization by coal rank, particularly for bituminous and subbituminous units.

One commenter (OAR-2002-0056-2944) disagreed with the proposal to subcategorize based on coal ranks. The commenter stated that coal rank is a continuous variable, a function of degree, not one of kind, stretching from before peat on the one end to past anthracite on the other. The commenter noted that these classifications grade into each other and in many cases can be subject to dispute and added that, as noted in the proposed rules, the ASTM classification of coal rank has overlapping attributes.

One commenter (OAR-2002-0056-2944) noted that U.S. boilers commonly fire mixes of coals of different ranks, citing information from the ICR that although around 215 utility boilers burned only subbituminous coals, nearly as many burned both combinations of subbituminous and bituminous. The commenter added that about 25 percent of the boilers that burned lignite burned other coal ranks as well. The commenter further stated that over the last two decades a very significant number of U.S. plants converted their boilers from burning high-sulfur bituminous coals to low-sulfur subbituminous coals to reduce their SO_2 emissions. According to the commenter, obviously, there is nothing particularly unique about coal rank that should lead to subcategorization and dramatically different Hg emission limits. The commenter observed that U.S. coal-fired boilers burn combinations of many carbonaceous fuels: in addition to lignite, subbituminous, and bituminous coals they burn anthracite, petroleum coke, waste subbituminous, waste bituminous, waste anthracite, biomass, and waste tires. The commenter asked is it logical, or practical to have separate emission standard determinations for each. The commenter further asked how can compliance be fairly determined at the over 20 percent of plants that burn multiple fuels simultaneously.

The commenter continued that the three primary coal-fired boiler fuel types contain Hg relative to their heating value at about the same degree. The commenter stated that each coal rank has about 70 percent of its deliveries with Hg contents measured between 4 and 14 pounds of Hg per trillion British thermal units (lb/TBtu). The commenter added that median Hg contents of each coal rank are also similar at 7, 5 and 8 lb Hg/T Btu for bituminous, subbituminous, and lignite respectively. (The commenter further noted that although subbituminous coals contain less Hg than bituminous coals, they ended up being allowed to emit nearly three times as much in the currently-proposed regulations.) The commenter stated that there is nothing obvious about the Hg content of coals of different ranks that justifies subcategorization.

Response:

EPA believes that there are sufficient differences in the design and operation of utility boilers utilizing the different coal ranks to justify subcategorization by major coal rank. As

documented in the record, utility boilers vary in size depending on the rank of coal burned (i.e., boilers designed to fire lignite coal are larger than those designed to fire subbituminous coal which, in turn, are larger than those designed to fire bituminous coal). Boilers designed to burn one fuel (e.g., lignite) can not randomly or arbitrarily change fuels without extensive testing and tuning of both the boiler and the control device. Further, if a different rank of coal is burned in a boiler designed for another rank, either in total or through blending, the practice is only done with ranks that have similar characteristics to those for which the boiler was originally designed. That is, the ASTM classification system is structured on a continuum based on a number of characteristics (e.g., heat content or Btu value, fixed carbon, volatile matter, agglomerating vs. non-agglomerating) and provides basic information regarding combustion characteristics. Because more than one characteristic is used, the possibility exists for numerous situations where a coal could be "classified" in one rank based on one characteristic but in another rank based on another characteristic. Ranking is based on an evaluation of all characteristics. Therefore, it is possible that (for example) a non-agglomerating subbituminous coal with a heating value of 8,300 Btu/lb (ASTM classification III.3–"Subbituminous C coal") could be co-fired with, or substituted for, a non-agglomerating lignite coal with heating value of 8,300 Btu/lb (ASTM classification IV.1--"Lignite A coal"). This does not, however, mean that it is possible for a boiler designed to burn the Lignite A coal to burn an agglomerating coal with a heating value of 13,000 Btu/lb (e.g., ASTM classification II.5–"High volatile C bituminous coal"). Further, it does not mean that the substituted coal would exhibit the same "controllability" with respect to emissions reductions as the original coal, regardless of its compatibility with the boiler. The fact that a number of Utility Units co-fire different ranks of coal does not negate the overall differences in the ranks that preclude universal coal rank switching, particularly when the design coal ranks are not adjacent on the ASTM classification continuum.

Although other classification approaches have been suggested (e.g., based on the geologic age of the coal; see OAR-2002-0056-5411), the ASTM classification system remains the one most recognized and utilized by the industry and the one which the EPA believes is most suitable for use as a basis for subcategorization. EPA further believes that, at this time, coal rank is an appropriate and justifiable basis on which to subcategorize for the purposes of this rule. We address elsewhere in this document comments related to the appropriate emission level for each subcategory.

2.2.3 Single Subcategory for Bituminous and Subbituminous

Comment:

Many commenters (OAR-2002-0056-1675, -1677, -1762, -1848, -1852, -1853, -2160, -2269, -2660, -2826, -2860, -2871, -2878, -2875, -2889, -2904, -2905, -2908, -2937, -2944, -3205, -3324, -3366, -3394, -3406, -3435, -3449, -3560) opposed subcategorization and setting different limits for bituminous and subbituminous coal ranks. Some commenters (OAR-2002-0056-1675, -2160, -2871, -2889, -3324, -3394) stated that such subcategorization discriminates against bituminous coal and could result in increased emissions as plants switch to subbituminous coal to take advantage of the lax limit, rather than install Hg controls. Two commenters (OAR-2002-0056-2871, -2889) stated that the final rule should address the lax

requirement for subbituminous coal by requiring a stricter limit for subbituminous coal (i.e., 80 percent). One commenter (OAR-2002-0056-3406) stated that the rationale for subcategorization presumably is that Hg emissions from subbituminous coal are more difficult to control. The commenter believed, however, this is almost certainly a short-term problem in light of the progress that has been and is being made with respect to the development of Hg controls for this coal rank and that development of these needed controls for subbituminous coal actually will be stalled if strict control standards are not promulgated. Another commenter (OAR-2002-0056-2160) stated that when Hg-specific control technologies are commercialized, there will be no differentiation in their performance for different ranks of coal, which they say, is supported by preliminary data which indicates that there are no removal differences between bituminous and subbituminous coals using the compact hybrid particulate collector (COHPAC) technology.

Two commenters (OAR-2002-0056-2878, -3205) cited the paper, "Mercury Air Pollution: The Case for Rigorous MACT Standards for Subbituminous Coal," to support their contention that there is no technical justification for the separate subcategories. The commenters stated that the technology is available that can achieve 90 percent reduction at the same costs for both ranks of coal using ACI and an ESP and COHPAC baghouse for particulate collection and nearly all the western plants are already equipped with either an ESP or baghouse. According to the commenters, subcategorizing these two ranks of coal also may result in plants switching or locking into using the dirtier western subbituminous coal because of the more lenient limits. The commenters also stated that separate limits would be difficult to implement and enforce because many plants burn both ranks of coal, some coals cannot be classified as either rank under the ASTM standard, and the amounts vary from month to month and year to year. One commenter (OAR-2002-0056-3205) stated that the proposed Roundup power plant provides a perfect example of the implementation issues that arise with EPA's proposed subcategorization. A review of 300 samples from various points across the nearby basin from which the plant's coal would come could not be classified as bituminous or subbituminous by ASTM standards.

One commenter (OAR-2002-0056-3205) stated that EPA fails to provide an adequate rationale to justify weaker standards for units burning subbituminous coal. In opposing separate subcategories for units burning bituminous and subbituminous coal, one commenter (OAR-2002-0056-3406) explained that companies are increasingly attempting to capture subtle changes in fuel price and viewing fuel supply as a compliance option, with the result that many companies use various blends of coal to optimize their emission performance. The commenter believed that the use of subcategories may significantly limit the flexibility to manage a facility's operational conditions and fuel choice; in the context of a competitive market for supplying electric generation, operational flexibility and fuel choice are of paramount importance. One commenter (OAR-2002-0056-3435) stated that the variability of the Hg and Cl content of coal within a rank, the ability of a unit to burn more than one rank of coal, and the magnitude of the difference in emission limits diminishes the merit of subcategorization by coal rank, particularly for bituminous and subbituminous units.

One commenter (OAR-2002-0056-3449) opposed subcategorization by coal rank stating that subcategorization results in more blending of subbituminous coal at existing bituminous

units. The commenter stated that coal blending is becoming more common and can result in Hg emission reductions (30 to 40 percent subbituminous coal with about 60 to 70 percent bituminous coal reduced Hg emissions by about 35 percent at one plant). According to the commenter, this is because subbituminous coal has less Hg and the combination of blend characteristics and existing controls for bituminous coal maintains the efficiency of Hg control for the blend. The commenter stated that this contradicts EPA's assumption that it is harder to control Hg from subbituminous coal. According to the commenter, it may be that the lack of control systems, especially for NO_x, will cause lower Hg removal at some subbituminous plants.

One commenter (OAR-2002-0056-2860) favored a single category for bituminous and subbituminous coal stating that a fuel-neutral standard would facilitate compliance by simplifying recordkeeping and reporting for the type of fuel burned. The commenter also stated that it was not clear in the ICR database how EPA determined which sources are considered in each subcategory because a number of sources identified one fuel as primary yet tested another fuel.

Two commenters (OAR-2002-0056-1848, -1853) opposed subcategorization for subbituminous coal as unnecessary and potentially illegal, stating that the decision is at odds with the FACA workgroup as evidenced in October 30, 2002, memorandum.

Some commenters (OAR-2002-0056-2826, -3560) stated that because of the CAA and rules relevant to SO_2, several Midwest utilities switched to low sulfur western subbituminous coal, thereby increasing the amount of Hg that was emitted. Yet, under the proposed Hg rules, power plants burning low-sulfur western coal will be subject to less strict Hg emissions limits than plants that burn bituminous and coal refuse. Those power plants that switched to lower sulfur coal will benefit from the less stringent Hg standard, even though these plants are emitting more Hg. The commenter stated that they should not be penalized for making the choice to continue to burn coal refuse and bituminous coal, rather than switching to low-sulfur western coal, especially when it has in place on both units all the technology considered sufficient for compliance.

According to one commenter (OAR-2002-0056-2905), Wisconsin recently completed a Hg rule that is reasonable, achievable, and cost effective and urges EPA to promulgate a more stringent rule, particularly for subbituminous coal. According to the commenter, Wisconsin, where many utilities rely heavily on western subbituminous coal, requires a 40 percent reduction by 2010, 75 percent by 2015, and 80 percent by 2018.

One commenter (OAR-2002-0056-3435) recommended a single subcategory for existing units burning bituminous and subbituminous coal with separate subcategories for lignite, coal refuse-fired, and IGCC units. The commenter stated that according to EPA, an estimated 23 percent of the coal-fired utilities burn two or more ranks of coal in the same boiler. Because the proposed rule does not prohibit a utility from fuel switching, the commenter stated that a unit could switch to a lower rank coal and increase emissions by as much as 190 percent. The commenter argued that combining bituminous and subbituminous units in one category would preserve flexibility for fuel blending and switching without affecting the applicable emission

standard. Although fuel switching is not an option due to design limitations, the commenter stated that there are plants that are capable of burning both ranks of coal. According to the commenter, if other coal ranks such as lignite are given a separate limit, the use of lower rank coal should be subject to approval, considering either the operation of the facility or other environmental impacts, such as NO_x or SO_2 reductions. Another commenter (OAR-2002-0056-3406) recommended a single standard for existing pulverized coal units burning bituminous and subbituminous coal.

Response:

As noted above, EPA believes that subcategorization by coal rank, including for bituminous and subbituminous ranks, is appropriate in this case. The ability of some units to burn more than one rank of coal does not override the overall appropriateness of the approach. We will address later in this document the respective emission limits for the various coal ranks. Further, we believe that the regulatory approach being taken (e.g., cap-and-trade) will address the monitoring and recordkeeping concerns raised.

Comment:

One commenter (OAR-2002-0056-1852) sought clarification on how EPA will calculate a Hg emission standard, based upon the proposed subcategories, for coals that have undergone pre-combustion. According to the commenter, pre-combustion technology alters a fuel's chemical and physical properties so that the end resulting fuel does not resemble the initial feedstock.

Response:

Under the approach being taken for the final rule (i.e., cap-and-trade), units will be assigned Hg allocations. Compliance with the allocated Hg emissions "cap" may then be accomplished by any means the owner/operator chooses.

Comment:

One commenter (OAR-2002-0056-2269) recommended combining subbituminous coal and western bituminous coal into a single subcategory because:

(1) The similar low sulfur, low Hg, low Cl, and high calcium content of western bituminous and subbituminous coal is consistent with similar Hg flue gas speciation (and consequently, similar emission control performance);

(2) Combining them into a single class simplifies equitable development and enforcement of rules; and

(3) The amount of Hg in western bituminous coal is only 5 percent of the total Hg in coal burned in the U.S., so this change would have a negligible effect on emission reductions.

They recommended that the same limits as proposed for subbituminous coal also apply to western bituminous coals at new and existing plants. The commenter believed that the proximity of subbituminous and bituminous coals in the west will cause market impacts and complicated oversight if limits are specified by rank. The commenter stated, for example, both kinds of coal may be produced from a single mine or a single county or region. And, where the ASTM rank parameter is near the subbituminous/bituminous threshold, the commenter stated that regulators will need to consider complicated scientific factors as well as the impact of the sampling method on moisture content to know which rank is which. The commenter also recommended that State Hg budgets should be revised to reflect coal origin, where the algorithm used for plants burning subbituminous coal is also used for plants burning western bituminous coal and adjusted in proportion to their fractional share of western bituminous coal as needed.

Response:

As noted above, although EPA recognizes that the ASTM classification system may not be perfect and, in fact, has occurrences of overlap, it remains the most widely accepted system and, therefore, is appropriate for use in subcategorizing for the purpose of this rule.

2.2.4 Lignite

Comment:

To recognize the differences in lignite coals, several commenters (OAR-2002-0056-1803, -2054, -2422, -2844, -2867, -2915, -3327, -3440, -3463, -3469, -3510, -3543, -4191, -4891) stated their support for creation of a subcategory for units burning Gulf Coast lignite separate from units burning Fort Union lignite. One commenter (OAR-2002-0056-3543) supported a separate subcategory for Gulf Coast lignite because the current rule structure could force generators to switch coal ranks, primarily from lignite and subbituminous to bituminous coal. According to the commenter, Gulf Coast lignite is substantially different from other lignite coals and, because it is an important fuel source, should remain viable. The commenter stated that under a cap and trade approach, the subcategorization should be used to determine allocations for State Hg budgets. According to some commenters (OAR-2002-0056-2054, -2422, -3510, -4191), the higher Hg content of Gulf Coast lignite and higher Hg emissions from units burning Gulf Coast lignite versus Fort Union lignite for similarly controlled boilers justifies separate subcategories and higher emission limits for units burning Gulf Coast lignite. Several commenters (OAR-2002-0056-2915, -3463, -3478, -4191) stated that inaccurate analytical methods (method ASTM D 3684 for coals with high ash and moisture content) used during EPA's Hg ICR coal sampling gave erroneously low Hg content readings for Gulf Coast lignite in comparison to more accurate analytical methods. Using a new analyzer and ASTM D 6414 method, the commenter stated that Hg in fuel averaged a six-fold increase over the other method. A commenter (3478) stated that they believe that all high ash coals may have a higher Hg content in the coal than the ICR data reveals and if this is the case, and the stack emissions are also higher, then EPA has proposed a much more stringent standard than a 70 percent reduction. The commenter further discusses the problems with the test methods used to analyze for Hg and Cl in these samples and stated that the allowance allocations must be based on a baseline

adjustment factor of at least 3 for lignite plants to meet the targets.

Several commenters (OAR-2002-0056-2915, -3463, -4191) stated that if EPA does not establish a separate subcategory for Gulf Coast lignite with a higher emission standard, they should offer an alternative percent reduction option.

Response:

EPA continues to believe that there is insufficient evidence available to justify separate subcategories for Gulf Coast and Fort Union lignites. The reanalysis of the data in support of the revised new-source NSPS Hg emission limits, discussed later in this document, incorporated data from units firing both types of lignite, further lessening the necessity of additional subcategorization. EPA will continue to evaluate the Hg emission data that becomes available, including that generated through the studies on emerging Hg control technologies by the U.S. Department of Energy (DOE), and reassess the issue of further subcategorizing lignites during the normal NSPS review cycle.

Comment:

Although one commenter (OAR-2002-0056-3406) supported the separate treatment of lignite through the subcategorization process, the commenter adds that a great deal of research and development is focused on controlling Hg emissions from lignite coal, and strict control standards will certainly further fuel these development efforts.

Response:

EPA concurs with this comment and believes that the regulatory approach being taken will further serve to advance the development of improved Hg control technologies.

2.2.5 Integrated Gasification Combined Cycle (IGCC)

Comment:

One commenter (OAR-2002-0056-2948) opposed including IGCC units in this rulemaking because those units differ fundamentally from electric steam generating units.

Response:

EPA agrees that IGCC units differ fundamentally from other types of coal-fired electric utility steam generating units in their mode of combustion and operation. However, they remain "fossil-fired electric utility steam generating units" under the subpart Da definitions of "fossil fuel" and "electric utility steam generating unit" (see 40 CFR 60.41a) currently included in subpart Da and, therefore, are included within this rule.

2.2.6 Coal Refuse

Comment:

According to one commenter (OAR-2002-0056-2160), waste coals are insignificant in the overall fuel mix; there is no value in regulating them separately, which creates unnecessary complexity.

One commenter (OAR-2002-0056-2162) stated that waste coal-fired plants should not be subject to the proposed Hg rules.

Response:

Although insignificant in the overall mix of fuels used in Utility Units, coal refuse-fired units are typically utilized in fluidized bed combustors (FBC), a type of boiler not in general use for other coal ranks. For this reason, coupled with the fact that their emission characteristics are dissimilar from other coal ranks, EPA is considering coal refuse as a separate subcategory for purposes of this rule.

Comment:

According to one commenter (OAR-2002-0056-2920), EPA must regulate plants burning waste coal refuse, including culm, gob, and subbituminous coal refuse, as incineration units under CAA section 129. According to the commenter, it is not relevant whether a unit recovers energy from the combustion of waste (coal refuse-burning plants do not fall into the exception for specific energy recovery units under section 129(g)(1)). The commenter stated that EPA's failure to regulate coal refuse-burning power plants as incinerators under section 129 contravenes the CAA.

Response:

Coal refuse is a recognized subcategory under subpart Da (see 40 CFR 60.41b); this revision of the rule merely continues to consider "coal refuse" as a subcategory of "fossil fuel-fired electric utility steam generating units."

Comment:

One commenter (OAR-2002-0056-2842) noted that EPA proposed to include all waste coal units in a single subcategory, regardless of the rank of waste coal burned and stated that EPA must establish separate waste coal subcategories based on coal rank or otherwise adjust the waste coal emission limits to reflect the control and other issues that would be expected to be associated with subbituminous or lignite waste coals. The commenter also stated that EPA must modify the limits to account for the possibility that the units used to develop the limits might burn any rank of waste coal from any source, which, depending upon the Hg content and control issues of the Hg in the coal, would require adjustments to the limits. According to the

commenter, waste coal units have the same issues EPA identified for conventional units regarding coal rank. The commenter also stated that EPA has based the limits on data from only two units, both of which fired waste bituminous coals, and ignored the fact that waste subbituminous and lignite coals can be expected to have the same issues concerning emissions controllability as the coal ranks from which the waste coal is derived. The commenter also stated that EPA must take the same considerations into account to the extent that it considers a rule under CAA section 111.

Response:

As the commenter noted, EPA used the only coal refuse data available in establishing the proposed NSPS emission limits. No additional coal refuse emission data were provided during the public comment period; therefore, EPA has no additional data upon which to base any further subcategorization of the "coal refuse" subcategory. As discussed later in this document, EPA is, however, reassessing the approach taken to develop the new source NSPS limits.

Comment:

One commenter (OAR-2002-0056-3525) stated that waste-fuel combustion is a variable process, because the waste varies from mine site to mine site. According to the commenter, existing CFB plants are among the newest of the boiler fleet in this country, most having been built to meet best available control technology (BACT) requirements within the last 15 years. According to the commenter, all of the units with which he is aware have current Hg removal rates of 96 to 99 percent. The commenter stated that using more restrictive input limits on these units appears to be punishing facilities that made early investment in technology. The commenter stated that the variability of Hg content in the fuel is greater than that of regular coal and that carbon injection and other Hg removal methods currently under study are not directly adaptable to CFB design operations. The commenter stated that if variability of fuel quality justifies the proposed limit for bituminous coal, then at least a similar limit seems reasonable for a unit combusting waste products from bituminous coal mining processes. The commenter asserted that assignment of less than 20 percent of that value to units that currently meet BACT is overly restrictive and discriminatory, as well as arbitrary and capricious. The commenter submits that similarly, emission limits for firing of other rank coal wastes should be at least the level of limits applied to those other respective coal ranks.

Response:

EPA disagrees that the limits proposed for coal refuse-fired units is arbitrary and capricious given that the limits are based on data from such units and were not extrapolated from non-coal refuse-fired units. As discussed later in this document, EPA is, however, reassessing the approach taken to develop the new source NSPS limits.

Comment:

According to one commenter (OAR-2002-0056-2162), EPA may only regulate waste

coal-fired sources as part of the broader category of electric utility steam generating units, rather than as a distinct subcategory subject to a unique emission limitation. The commenter pointed out that EPA has developed a unique, and unduly stringent, Hg emission control level applicable only to waste coal-fired units without making a finding that emissions from waste coal-fired sources would pose a hazard to public health, or that the regulation of such units is "appropriate and necessary." According to the commenter, EPA's finding that it is "appropriate and necessary" to regulate Hg emissions for electric utility steam generating units applied generally to all coal-fired sources in that source category and that it is inconsistent, therefore, for EPA to distinguish waste coal-fired sources under the proposed rule as a separate and distinct source category subject to unduly stringent emission limitations. The commenter stated that any determination to regulate Hg emissions from waste coal plants–as sources that are "reasonably anticipated to cause adverse health effects"–only can be justified under EPA's statutory mandate, if at all, if waste coal sources are members of the broader source category of electric utility steam generating units. Accordingly, in order for the Agency to appropriately regulate waste coal plants, it must not distinguish between waste coal plants and other coal-fired electric utility steam generating units in establishing proposed emission limits. For these reasons, if the Agency regulates waste coal fired sources under the Proposed Mercury Rules, the commenter argued that the Hg emission levels applied to waste coal-fired sources must be consistent with those applied to conventional coal-fired sources, such as sources firing bituminous coal.

Response:

As noted earlier, EPA believes that it has the statutory authority to subcategorize "fossil fuel-fired electric utility steam generating units" for purposes of regulation under CAA section 111. Further, based on the subcategorization, EPA proposed a unique Hg emissions limit for each of the subcategories and does not believe that any are "unduly stringent" as the commenter asserts, given that each was based on the data available. As discussed later in this document, EPA is, however, reassessing the approach taken to develop the new source NSPS limits.

2.2.7 Fluidized Bed Combustors

Comment:

Several commenters (OAR-2002-0056-2375, -2911, -2918, -2948, -3537) supported a subcategory for FBC units. Three commenters (OAR-2002-0056-2375, -2918, -3537) stated that EPA should create a subcategory for FBC units to subsume the proposed subcategory for units that combust waste coal because FBC units use a fundamentally distinct process for fuel combustion that implicates differences in design, construction, and equipment. According to the commenters, such differences are sufficient to establish that FBC units constitute a different "class" or "type" of utility steam generating unit. Both commenters stated that subcategorization is further warranted because the FBC unit process and design differences have significant implications for Hg removal efficiency. One commenter (OAR-2002-0056-2918) provided a list of the main differences between FBC units and conventional boilers and stated that these differences are important for the higher Hg removal efficiencies of FBC units and such

differences should make FBC units a distinct subcategory. The commenter offered examples of when EPA has created subcategories among sources due to the performance of control technology (i.e., steel pickling and phosphoric acid manufacturing MACT).

Two commenters (OAR-2002-0056-3445, -3556) supported EPA's proposed subcategories based on coal rank but feel additional subcategorization, specifically a separate category for FBC units, is appropriate because FBC units use a fundamentally different combustion process than pulverized-coal units, making them a different type of source.

Response:

EPA agrees that FBC units operate and are designed differently than conventional pulverized coal (PC) boilers. However, with the exception of FBC units firing coal refuse, there was no clear indication from the available data that such units impacted on the ultimate Hg control effected. That is, in some cases, FBC units had higher removal rates than most with respect to their Hg emissions; in other cases, FBC units had lower removal rates than most. Therefore, EPA concluded that it was the coal rank, rather than the process type (e.g., FBC, PC) that should govern in any determination relating to subcategorization.

2.2.8 Fuel Switching and Impacts on U.S. Coal Supply

Comment:

Many comments were received regarding fuel switching and the impacts of the proposed rule on fuel switching. Several commenters (OAR-2002-0056-1969, -2067, -2260, -2834, -2897, -3198) agreed with EPA that fuel switching is not practicable to meet the proposed Hg emission limits. One commenter (OAR-2002-0056-2260) stated that furthermore, there exists no one fuel in sufficient quantities and availability that can be used by all utilities. The commenter's boilers were designed to burn western subbituminous/bituminous coals and cannot switch to burn eastern bituminous coals. Eastern coals also have higher levels of sulfur and would overload their scrubber control units. The commenter's remote location in southeastern Arizona also makes it impossible to transport coals from regions other than the west. Additionally, the commenter's units are limited in the amount of natural gas that can be burned because of severe constraints on the natural gas supply in the region.

One commenter (OAR-2002-0056-1969) stated that EPA has appropriately concluded that fuel switching is not a compliance option which is consistent with the CAA and favors the development of consistent standards that do not create regional inequities or favor one fuel type over another.

One commenter (OAR-2002-0056-2945) stated that any fuel switching or shift in coal utilization away from bituminous coal due to the proposed rules would have a drastic adverse impact on mining employment and on electric power generation.

One commenter (OAR-2002-0056-2891) stated that cooperatives believe that fuel

switching is not a reasonable or practical alternative for many units to meet the new emission limits and that in many cases, plants may have no option but to shut down.

Response:

Modeling done in support of EPA's proposed rules does not indicate that a significant amount of fuel switching will be undertaken by the utility sector to comply with the proposed rules. Some companies may chose to change fuels to effect compliance with either the CAIR or CAMR, or both. Further, EPA believes that some sources have extremely limited options (in some cases, no options) with regard to other coals or fuels that could be fired at a given Utility Unit. Therefore, EPA proposed emission limits that would be achievable for such units that would not require fuel switching.

Comment:

Some commenters were concerned over the impacts of the rule on bituminous coal. One commenter (OAR-2002-0056-3445) stated that in addition to coal-fired power plants which burn bituminous coal, they also own and operate bituminous coal mining and terminal operations. The commenter stated that any Hg regulation must treat all coals fairly. The commenter added that providing an advantage to coal from one region over coal from other regions encourages fuel switching as a compliance strategy and could limit the diversity of fuels available for electrical generation. The commenter stated that it is critical to the nation's security that all forms of coal continue to be available for electrical generation.

One commenter (OAR-2002-0056-2845) stated that any rule must not favor one rank of coal over another and that, although fuel switching appears to be an acceptable control option, it will severely reduce employment in the bituminous coal sector.

One commenter (OAR-2002-0056-2692) stated that the proposed rules threaten the future of the Appalachian coal industry. The commenter stated that industry and elected representatives from western States have for some time pushed EPA for a rule that would advantage western coal. According to the commenter, EPA responded to these concerns by publishing rules on January 30, 2004, that provide a major disadvantage to eastern coal. The commenter stated that specifically, the rules as proposed require sharp cuts in Hg emissions from eastern bituminous coals, but require far smaller cuts from the subbituminous and lignite coals of the west. According to the commenter, this difference in treatment is so great that it will certainly produce an illogical result: utilities will be encouraged to burn more western coal, despite the fact that it has higher levels of Hg. The commenter stated that the result will be more pollution and less eastern coal jobs.

One commenter (OAR-2002-0056-3469) stated that the Hg rule and the CAIR will further concentrate U.S. coal supply among Wyoming Southern PRB subbituminous coal producers and delay emission control technology retrofits and further erode production from the Illinois Basin as well as niche coal and lignite production regions, including certain Indian reservations.

One commenter (OAR-2002-0056-2661) stated that EPA's generalities of Hg emissions in coal, as a one size fits all, implies a greater burden for subbituminous coal users. The commenter noted that substantial reductions in SO_2 and NO_x were achieved by the conversion to low sulfur coal - subbituminous coals. The commenter stated that units that have borne the economic burden for fuel switching should not bear a disproportionate burden of Hg emission reduction strategy now. Further, the commenter did not believe it is in the best interest of the U.S. energy policy to favor limited coal choices based on any emission threshold currently established by EPA. According to the commenter, EPA's policy would continue to hamper U.S. energy needs and reliance on foreign and other inappropriate sources of fuel for U.S. consumer energy needs.

One commenter (OAR-2002-0056-3531) expressed concern with the discriminating impact the proposed rule will have on Ohio and other eastern bituminous coals. The commenter stated the current rule proposals may allow sources burning western coal to continue to do so without installing any control technologies. The commenter stated that essentially, the cost of all Hg reductions under the current proposal would be borne entirely by sources burning eastern coals, such as in Ohio. According to the commenter, there is no valid technical or economic justification for such discrimination. The commenter stated that Hg reductions must be based on an examination of the best-controlled sources in each fuel subcategory and a valid determination of the level of control that can be achieved within each subcategory. The commenter concluded that EPA must revise the rules to not favor regional fuel usage and, instead, require reductions for all sources based on available technical data. One commenter (OAR-2002-0056-2870) encouraged EPA to adopt approaches to control Hg emissions from power plants that will ensure a level playing field among all coal ranks and will promote an equitable strategy to address interstate pollutant transport. The commenter claimed the rule creates an uneven playing field that would harm the bituminous coal industry and its coal miners. One commenter (OAR-2002-0056-2937) recognized that although difficult regulatory decisions must be made, the commenter felt that good science, coupled with a sense of fairness can produce a rule that yields Hg reduction in a way that does not compromise the viability of bituminous coal producing regions.

Response:

EPA's modeling has shown little significant coal switching as a result of the proposed CAMR and CAIR actions. We believe that this rebuts the commenter's suggestions that one or another coal rank is "advantaged" or "disadvantaged" with respect to other coal ranks. EPA's responses to comments on the allocation adjustment factors are found elsewhere in this document.

Comment:

Many commenters (OAR-2002-0056-1625, -1673, -1768, -1802, -2020, -2066, -3478, -3513, -3517, -3530) expressed concern over the impacts of the proposed rule on the nation's energy supply. Several commenters (OAR-2002-0056-1673, -1768, -3478) believed that the Hg levels set by this rulemaking should not result in the loss of viability of any fuel type, such as

lignite, considering the severe impact this would have on local communities, jobs and the nation's energy security from the loss of this significant domestic fuel supply for electric generation.

One commenter (OAR-2002-0056-3513) stated that the nation's largest energy supply will be unduly impacted if EPA fails to adequately consider the vital role that coal-based electricity plays in America's current and future economic prosperity; the demand for electricity is growing and other fuels–such as natural gas–cannot meet this growing demand.

One commenter (OAR-2002-0056-3517) stated that coal represents our single largest domestic reserve of fossil fuel, representing 95 percent of the reserves (as compared to crude oil at 2 percent and natural gas at 3 percent). The commenter asserted that coal is electricity, accounting for 87 percent of the use of coal in the nation, and is responsible for 50 percent of total electricity generated in the U.S. The commenter believed it is incumbent upon EPA to promulgate responsible and achievable standards so as to not impact the reliability and cost of electric service.

Several commenters (OAR-2002-0056-1768, -3530) stated that the final rule must be consistent with the need for reliable and affordable electric power, including affordable use of all coal ranks and options for efficient on-site power generation such as CHP. The commenter stated that the final rule must facilitate–not discourage–the availability of an adequate and diverse fuel supply for the future, including coal, natural gas, nuclear energy, hydroelectric, and renewable sources. According to several commenters (OAR-2002-0056-1768, -2066), the final rule must not aggravate the already precarious natural gas supply which is currently inadequate. One commenter (OAR-2002-0056-2066) stated that these actions will inhibit, if not totally eliminate, plans for any new coal-fired base load electric generation, and this forgone option will undoubtedly be replaced by additional natural gas-fired generation.

Should EPA proceed with the rulemaking, one commenter (OAR-2002-0056-2847) urged the agency to adopt sufficient subcategories of expected reductions so as to limit the potential for economic disruption in the coal, transportation, and utility industry sectors.

Although supporting full use of categories and subcategories to adequately address differences in abilities to reduce Hg based on such things as coal chemistry that varies with coal rank, one commenter (OAR-2002-0056-3200) stated that it is imperative that no fuel type be afforded an unfair market advantage and that overly aggressive mandatory reductions in Hg emissions be avoided that would lead to loss of fuel diversity, higher energy prices and a strain on electric reliability, all of which are inconsistent with sound energy policies.

Several commenters (OAR-2002-0056-1675, -2160, -2660, -2875, -2904, -2908, -2937, -3324, -3366, -3560) stated that limits that favor one coal over another may have considerable economic impacts due to the higher control costs affecting coal producers, utilities, and customers. According to two commenters (OAR-2002-0056-2875, -2937), a significant loss of employment would occur in the Appalachian areas of their State and would be devastating to an area already suffering from excessively high unemployment rates.

Several commenters (OAR-2002-0056-1675, -1677, -1762, -2944) stated that subbituminous coal, which is primarily produced in the West, will receive favorable treatment at the expense of eastern bituminous coal that will make bituminous coal virtually non-competitive with western subbituminous coal. One commenter (OAR-2002-0056-2944) stated that subcategorization will result in regional disparities and inconsistences in the industry which EPA stated that it intended to avoid.

One commenter (OAR-2002-0056-1852) opposed EPA's proposal to subcategorize stating that the widely varying proposed emission rates for coal subcategories could cause disruption to coal supplies and fuel blends in order for utilities to comply with the Hg standard.

Response:

As noted above, EPA's modeling has shown little significant coal switching as a result of the proposed CAMR and CAIR actions. We believe that this rebuts the commenter's suggestions that one or another coal rank is "advantaged" or "disadvantaged" with respect to other coal ranks. Further, we do not believe that the final rules will have a negative impact on the nation's energy security, employment rates, or energy reliability. Responses to comments on the allocation adjustment factors are found elsewhere in this document.

Comment:

One commenter (OAR-2002-0056-3198) stated that these regulations will have a tremendous impact on the mining industry in Wyoming and on the state as a whole and it is critical that EPA adequately address the unique chemistry of Wyoming coal.

Response:

EPA believes that it has adequately addressed the commenter's concerns in the rule through the finalizing of two emission limits for subbituminous coals, depending on the type of FGD unit used and the allocation factors used in the trading program.

Comment:

According to one commenter (OAR-2002-0056-3254), Illinois Hg emissions have risen about 28 percent while burning western coal. The commenter stated that Illinois coal Hg content is 1/3 that of western coal and that EPA should not allow western coal to be burned.

Response:

EPA does not feel that it is in the best interest of the country to prohibit the use of some ranks of coal when those coals can be adequately controlled to limit Hg emissions.

Comment:

One commenter (OAR-2002-0056-3525) encouraged EPA to reduce Hg emissions without undermining fuel diversity. The commenter believed that flexibility will more likely be achieved through EPA's market-based, cap-and-trade, approach to controlling Hg emissions than through the MACT approach. The commenter stated that the tight time frame for reductions in the Hg MACT approach could leave utilities with no real choice but to install a significant quantity of additional gas fired generation facilities and thereby switch fuels as a primary means of compliance. The commenter stated that market-based mechanisms, like the successful cap-and-trade program under the acid rain program, will dramatically increase the cost-effectiveness of any program. The commenter supported an approach of imposing Hg emissions reductions to a level commensurate with co-benefits achieved through the SO_2 and NO_x emissions reductions of the proposed CAIR. The commenter stated this will help mitigate the costs of compliance, which will be borne by all electricity consumers. According to the commenter, when establishing emission limits, the inherent fuel quality differences and the varying capability of emission control devices to capture Hg between coal ranks needs to be considered and properly accommodated. The commenter urged EPA to establish a rule that does not preferentially disadvantage a particular fuel or fuel type so that fuel diversity of the electrical generation sector is not artificially restricted.

Response:

EPA concurs with the commenter's belief that a cap-and-trade approach will better serve to protect the environment while at the same time allowing the industry to maintain fuel diversity.

2.2.9 Other Subcategorization Approaches

Comment:

One commenter (OAR-2002-0056-2422) suggested the following subcategorization approach: hot stack, wet stack, and saturated stack configurations. According to the commenter, this approach recognizes that many hot-stack eastern units fired with bituminous coals are not cost-effective candidates for capital-intensive control technology retrofits. The commenter believed that EPA should provide emission-based exemptions for relatively small Hg-emitting units to mitigate the substantial risks of plant closures among older and smaller units.

One commenter (OAR-2002-0056-2634) stated in addition to subcategorization by coal rank, further subcategorization could be warranted, based on pollution control process configuration and coal chemistry, due to its impact on Hg speciation and its ability to be controlled by present technology.

Response:

EPA believes that cost-effective emission reduction approaches are available for

"hot-stack" units, particularly when the CAMR is taken in concert with the CAIR. EPA analyzed the commenter's suggested subcategorization approach but believes subcategorization based on coal rank is more easily implemented and more adequately addresses the coal chemistry issue.

Comment:

One commenter (OAR-2002-0056-2267) believed that EPA should create a subcategory for small municipal generators under the MACT approach.

Response:

EPA sees no justification for creating such a subcategory. Such units are constructed and operated in a manner similar to other "electric utility steam generating units" and, as such, are sources of Hg emissions. Coal-fired municipal units otherwise meeting the definition would be subject to the final rule.

2.2.10 New Units

Comment:

Several commenters (OAR-2002-0056-1969, -2067, -2634, -2721, -2843, -3403, -3514, -3537) supported the proposal to use the same coal subcategories for new plants as for existing plants. However, one commenter (OAR-2002-0056-2067) stated that the EPA ICR reference data should be supplemented with more recent and representative power plants and coal sources. The commenter stated that Hg removal data used to set the standards for the best performing utility units must be accurate and represent the variations of coal within each coal rank. The commenter stated that standards for new power plants should be adopted to encourage the construction of cleaner coal plants and maintain a diverse mix of fuel.

One commenter (OAR-2002-0056-1969) stated that the historical fuel mix is indicative of regional and economic conditions and fuel needs and according to the commenter, selection of other subcategorization methodologies for new units could affect their future market conditions and an ongoing need for a diversified electrical generation fuel mix.

One commenter (OAR-2002-0056-2721) believed that without subcategorization, the location of new units will be biased geographically near the fuel types that provide for the ease of compliance. According to the commenter, this unfair siting advantage will place strenuous hardships on the electrical supply chain of the country and place economic hardship in areas of the western U.S. where typically the low Cl content of coal resides.

One commenter (OAR-2002-0056-3435) recommended a single subcategory for new units burning bituminous and subbituminous coal. The commenter stated that the difference in the limits for new bituminous and subbituminous coal would allow a 233 percent increase in emissions.

Response:

EPA continues to believe that new sources should be subcategorized in the same manner as existing units.

Comment:

One commenter (OAR-2002-0056-3459) stated that, although EPA has only spurious rationale for subcategorization of existing units, there is no rationale for new units. The commenter stated that these can be designed to provide optimum performance when firing all coal ranks and that EPA must reject subcategorization and establish a single limit for new units. According to the commenter, the effect of EPA's proposal is to make the standards less stringent by subcategorizing according to the rank of coal. The commenter stated that the words of a statute must be read in their context and with a view to their place in the overall statutory scheme and that Congressional intent was to use subcategorization sparingly; the same reasons the NO_x NSPS was fuel neutral (improvements in control technologies were available on all utility boilers) applies here.

Response:

EPA believes that the proposed requirement for new units to comply with an output-based emission limit will ensure that they are designed to achieve optimum performance. However, units designed to burn bituminous coals will still not be able to burn lignite coals (for example) and, thus, the need for subcategorization remains. As noted earlier, EPA concurs that advancements in Hg control technologies may lead to more "fuel neutral" formats; however, that time has not come.

Comment:

One commenter (OAR-2002-0056-3537) contends that IGCC units use fundamentally different processes than conventional boilers and should be placed in their own new unit subcategory.

Response:

EPA concurs that new IGCC units should continue to be subcategorized separately from other coal-fired units.

Comment:

One commenter (OAR-2002-0056-2862) stated that in establishing a new source NSPS for Hg, EPA should also subcategorize coal-fired power plants based on the process type. The commenter believed that it is vital that EPA further consider the performance of representative boiler types and variations in Hg content.

Response:

EPA does not believe that there is any additional justification for subcategorizing new units by process type than there is for existing units.

2.2.11 Coal Blends

Comment:

Two commenters (OAR-2002-0056-2535, -3435) favored a subcategory for units burning a blend of subbituminous and bituminous coals. One commenter (OAR-2002-0056-2535) believed that blends of subbituminous and bituminous coals should not be categorized under subbituminous coal. The commenter stated that EPA incorrectly set the limit for subbituminous coal by mis-classifying blended fuel units as subbituminous units, resulting in a erroneously higher number of plants classified as subbituminous plants. The commenter cited certain plants named by EPA as being subbituminous plants (e.g., Craig, La Cygne, Lawrence, Newton, and Presque Isle) as potentially burning blends of subbituminous and bituminous coal. For each of the plants identified as burning subbituminous coal, the Energy Information Administration (EIA) database was reviewed by the commenter to determine which mine the coal was shipped from in 1999. According to the commenter, EPA's Table 2 summary of the coal supply data as reported to the EIA for these plants, shows these plants categorized as subbituminous plants, but may instead be plants that burn a blend of bituminous and subbituminous coals. The commenter further stated that neither the EIA data nor the ICR data differentiates as to what coals were delivered to which unit within a facility, so the shipments listed above are for the plant as a whole for 1999. The commenter was unable to find any clear documentation as to what rank of coal was being burned during the EPA ICR tests. The commenter stated that unless EPA is able to accurately determine what coals were burned during the test, the assumption must be made that it was a subbituminous/ bituminous blend and the plant must be placed in the "blend" category. The commenter further stated as unsound the suggestion that any plant that burned over 90 percent subbituminous coal should still be classified as a subbituminous unit and that the remaining blend be considered a deminimus amount. The commenter stated that there needs to be a better evaluation of blended coals, and how these different ranks of coals interact relative to the species of Hg that is emitted.

Response:

As noted above, EPA does not believe that a subcategory based on blended use of bituminous and subbituminous coals is warranted. EPA relied on the facilities to provide accurate information regarding the rank of fuel burned and, in some cases, errors were corrected. It is true that some units noted by the commenter received shipments of multiple ranks of coal during the reporting period, they reported burning only one rank of coal during their emission test program and, therefore, have been classified as being in that subcategory. However, as noted later in this document, EPA has reevaluated the basis for the new source NSPS limits for the final rule.

Comment:

Commenter OAR-2002-0056-3459 states that EPA's proposed case-by-case alternative for units burning a blend of coals is unlawful. EPA must establish emission standards for each subcategory of sources that emit HAP and those standards are to be based on the best performing units within the subcategory. However, EPA does not propose a uniform standard for units burning a blend of coals and does not base the standard, such as it is, on the best performing units. Even though EPA effectively creates a subcategory for units burning a blend of coals, it makes no effort to establish standards for that subcategory.

Response:

The approach being taken for blended coals is consistent with the procedures already in-place in 40 CFR 60, subpart Da.

2.2.12 Other

Comment:

One commenter (OAR-2002-0056-2897) agreed with EPA's decision to subcategorize by coal rank and to differentiate between bituminous and subbituminous coals. The commenter also stated that the ICR data used to support the claim that PRB coal is compliant must be questioned. The commenter agreed with EPA's determination that the overlap in coal classification properties does not compromise its ability to subcategorize by coal rank and overlap only occurs in a very limited number of cases and it remains true that coal rank is a significant factor that distinguishes the design and operational characteristics of different boilers.

Response:

EPA has reanalyzed the data used to support the Hg emission limit for subbituminous coals. Discussion of this reanalysis is contained elsewhere in this document.

Comment:

Not all commenters (OAR-2002-0056-2661, -2692, -2870, -2937, -2944, -3208, -3469, -3531, -4139) agreed with EPA's use of subcategories. One commenter (OAR-2002-0056-2944) stated that the combustion processes involved in IGCC systems, FBC, and PC boilers are themselves fundamentally different in their mechanical operation and the resulting processes offer distinctly different possibilities for limiting Hg emissions. The commenter added that in actual practice each of these combustion types produces significantly different relative Hg emissions. According to the commenter, because the differences between these classes of coal combustors is a matter of kind, rather than one of degree, it is logical to determine separate emission limits for them. The commenter believed that because the combustion process, opportunities for limiting emissions, and typical emission results of cyclone boilers and stoker

boilers are very similar to those of PC boilers, it makes regulatory sense to combine them into the class of pulverized boilers.

Response:

As noted above, EPA concurs that IGCC units should be subcategorized separately but disagrees with the commenters with regard to FBC units.

Comment:

One commenter (OAR-2002-0056-4139) suggested that the logic used in establishing the subcategories needs to be reassessed.

Response:

EPA has reviewed its analysis leading to the proposed subcategories and continues to believe that the subcategories proposed continue to be appropriate.

Comment:

In addition to demonstrating the efficacy of ACI, one commenter (OAR-2002-0056-3208) and other participants in research funded in part by the U.S. Department of Energy's National Energy Technology Laboratory stated that they are exploring the potential use of oxidizing agents, enhanced sorbents, and coal blending as potential pathways to achieving significant reductions in Hg emissions from use of PRB coals. On this basis, the commenter urges EPA to adopt a separate subcategory for PRB coals within a subbituminous coal category.

One commenter (OAR-2002-0056-4139) agreed that the importance of coal ranks may diminish and that EPA should review its limits by coal rank periodically and make them more stringent if appropriate due to improving Hg control technology.

Response:

EPA stands by its decision with regard to subcategorization. Further, EPA believes that the research noted by commenter -3208 supports more limited, rather than broader, subcategorization scenarios (i.e., fewer, perhaps none, rather than more subcategories) when the rule is reviewed in the future as suggested by commenter -4139.

Comment:

According to some commenters (OAR-2002-0056-2364, -2430), EPA's straw proposals of August 2001 and December 2001 contained subcategorization possibilities calling for 90 percent control, have defensible MACT floors, are cost effective, have timely implementation, and are preferable to EPA's proposals.

Response:

The "straw proposals" noted by the commenters were extremely preliminary in nature and were never the basis for any proposal options. The data upon which the straw proposals were based were subsequently determined to be in error with regard to levels of Hg control achieved by existing controls. Further analysis of the available data also indicated that the subcategories used at proposal were appropriate.

2.3 GENERAL COMMENTS

Comment:

One commenter (OAR-2002-0056-2485), also noted that many sources of natural gas contain high levels of Hg and should be included in this subpart.

Response:

EPA received no data or information during the public comment period to indicate that its determination that regulation of natural gas-fired Utility Units was neither necessary nor appropriate was in error. Therefore, EPA stands by that decision.

RESPONSE TO SIGNIFICANT PUBLIC COMMENTS ON THE PROPOSED CLEAN AIR MERCURY RULE

Received in response to:

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 4652; January 30, 2004)

Supplemental Notice for the Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 12398; March 16, 2004)

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources, Electric Utility Steam Generating Units: Notice of Data Availability
(69 FR 69864; December 1, 2004)

Docket Number OAR-2002-0056

3.0 PERFORMANCE STANDARDS FOR COAL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

US Environmental Protection Agency
Emissions Standards Division
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

15 March 2005

General Outline

3.0 PERFORMANCE STANDARDS FOR COAL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

3.1 MERCURY CONTROL TECHNOLOGIES

Comment:

According to one commenter (OAR-2002-0056-2946), although there may be no single technology to meet the needs of all plants, a wide set of solutions are available for each subcategory. The commenter listed 10 control measures ranging from coal washing to switching to renewable resources.

Response:

EPA concurs that there are a number of technologies that may be used by utility units to reduce Hg emissions.

3.1.1 Availability of Mercury-Specific Control Technologies

3.1.1.1 Current Commercial Availability

Comment:

Several commenters (OAR-2002-0056-1826, -2020, -2160, -2578, -2929, -2948, -3445, -3463, -3478, -3537) stated that there are no commercially available control technologies specifically designed for Hg emission control from coal-fired power plants. Commenters acknowledged that existing control technologies used to control PM, SO_2, or NO_x emissions reduce Hg emissions under selected conditions and significant research is being conducting by the public and private sectors on new Hg control technologies. Although significant research is underway by the private and public sectors, before commercial availability is achieved, additional development is need to provide for new technologies that account for variability in coal content, combustion processes, and control system performance under different kinds of firing conditions.

One commenter (OAR-2002-0056-1814) stated that Hg is a naturally-occurring chemical that is emitted in trace amounts when coal is combusted. The low concentrations of Hg in coal make capture of Hg from power plants very difficult and subject to a great deal of variability. Technologies are not currently available that are specifically designed for control of Hg at the low concentrations emitted by power plants

One commenter (OAR-2002-0056-2861) stated that technology is not ready to support a regulatory program. The low concentration of Hg that occurs naturally in coal makes the capture of Hg from the flue gas of coal-fired power plants very difficult and subject to a great deal of

uncertainty and variability. According to the commenter, there currently are no commercially available technologies that are specifically designed to control the very low concentrations of Hg emitted by coal-fired power plants. The commenter stated that although some of the technologies being investigated have shown some promise, there are still many unanswered questions regarding the level of reduction that can reliably be achieved, the variables that will affect performance, and the impacts on overall plant operation and maintenance.

One commenter (OAR-2002-0056-2899) stated that for a technology to be deemed commercially available, it must be able to control Hg emissions from power plants burning different coal ranks and having different boiler types and configurations; a few isolated tests or demonstrations are not sufficient to conclude that a technology is commercially available. A technology needs to be installed in full-scale applications at a number of sites and operated over extended periods of time before it can be viewed as commercially available, and a technology is not commercially available just because a vendor is willing to sell it. The commenter points out that commercial availability requires that most of the key engineering questions about the technology need to have been previously resolved. The commenter added that a technology is not commercially available if one installs it knowing that many problems will need to be resolved as part of the installation and operation.

Response:

EPA concurs with the commenters and believes that Hg-specific control technologies are not yet commercially available.

Comment:

One commenter (OAR-2002-0056-3469) stated that lack of control and monitoring technology impedes speedy compliance. The issues relating to the state of science on Hg are compounded by a lack of technology to reliably measure or control Hg emissions, particularly from lignite-fired units, to justify the level of emission reductions proposed by EPA. As stated by the Department of Energy (DOE), "Today, there is no commercially available technology that can consistently and cost-effectively capture Hg from coal-based power plants."

Response:

EPA concurs that Hg-specific control technologies are not currently available. However, we disagree with respect to Hg monitoring technologies and believe that such systems will be available by the time compliance with the regulation is required.

Comment:

One commenter (OAR-2002-0056-3454) stated that the rapid development of Hg control technologies over the last several years has produced a number of technologies that are available for the implementation of a national Hg control regulation for coal- and oil-fired power plants. A large number of laboratory tests and full-scale demonstrations have been conducted that

provide information on the effectiveness of controls for various coal ranks and control configurations. Despite the current lack of a national control requirement for Hg, a number of options are commercially available while others are still in the development and testing phases.

One commenter (OAR-2002-0056-3210) stated that the EPA understates the availability of Hg control technology because it failed to acknowledge the DOE/National Energy Technology Laboratory Mercury Control Technology Research Program on coal-fired power plants.

Response:

EPA disagrees with the commenters about the availability of Hg-specific control technologies at the present time. EPA is fully aware of the DOE research program cited by the commenter. The limited, but increasing, number of tests have not yet brought the technologies to the level of demonstration that we feel necessary to be considered "commercially available" and the basis for a national standard.

Comment:

One commenter (OAR-2002-0056-2247) stated that sorbent injection technologies should be considered available for Hg. Permits have been issued that will rely on sorbent injection technologies such as ACI (MidAmerican Energy, Council Bluffs Unit 4, PSD permit issued by Iowa; and Wisconsin Public Service Corporation, Weston Unit 4, issued by Wisconsin). These show that Hg removal technologies capable of achieving more than 80 percent control are available.

Many commenters stated that EPA failed to consider Hg control technologies and methods that are currently available and cost effective. EPA must consider the costs and environmental effects of these technologies, such as ACI and other sorbent injection systems, coal washing, and selective catalytic reduction (SCR). New units can design these into their control systems without retrofit problems. EPA should also consider technologies required in consent decrees, case-by-case MACT and BACT analyses, State regulations, and permit data.

Response:

As noted earlier, EPA does not believe that Hg-specific control technologies, including ACI, are commercially available for nationwide application to the coal-fired utility industry. Installation of such technologies on a limited number of units (e.g., the two cited) is possible and will serve to advance the technologies such that they are widely for use in compliance with the phase II cap.

3.1.1.2 Mercury Control Technology Development Time

Comment:

Many commenters (OAR-2002-0056-1471, -1608, -1636, -1667, -1773, -1777, -1791, -1806, -1817, -1987, -2064, -2233, -2887, -2946, -3454, -3538) disagreed with the EPA's conclusion that Hg-specific controls for electric utility power plants will not be commercially available on a wide scale until 2010 or later. Other commenters agreed with EPA's time estimate on the availability of Hg-specific controls (OAR-2002-0056-1969, -3537, -3565). Arguments stated by various commenters disagreeing with EPA's assessment included the following. Mercury control technologies are available now. The EPA disregarded studies on emerging Hg control technologies. The EPA's own numbers and other studies indicate that coal-fired plants can achieve 90 percent reduction regardless of the type of plant or coal. Field testing of ACI has shown 90 percent capture of Hg. Units equipped with scrubbers and fabric filters can obtain near 90 percent. Studies indicate that the cost of these controls would be comparable to those for other pollutants and EPA disregards these studies and emerging state of the art Hg control technologies. The EPA did not provide a detailed analysis of the current available technologies. Outside of the U.S., the Berrenrath 275 MWe and the Wachtberg 166 MWe plants in Germany operate on carbon injection technology to control Hg. What is contradictory in EPA's analysis is that they used ACI in their cost modeling exercises with the integrated planning model (IPM) but failed to recognize this technology in setting the level of Hg reductions for the emission limits.

Several commenters (OAR-2002-0056-2873, -3449), although agreeing that ACI technology currently is not commercially available, stated that this technology will be available before 2010. One commenter (OAR-2002-0056-3449) stated that ACI can be developed and widely implemented within the next 6 years. A second commenter stated that ACI can be developed and widely implemented by 2008 to 2009.

Response:

EPA disagrees with the commenter's assessment regarding the time that it will take for ACI, or other Hg-specific control technologies, to become commercially available. We do not believe that these technologies are available now for wide-spread usage. We have been following the studies of such technologies closely and have discussed their degree of development with vendors, the industry, and the DOE. No utility unit has operated a Hg-specific control technology full-scale for longer than a month or so. Further, the technologies have not been fully evaluated on all coal ranks (e.g., Gulf Coast lignite), even under short-term conditions. In addition, other aspects of the use of Hg-specific control technologies (e.g., balance of plant, waste issues, other atmospheric concerns) have not been fully addressed. Studies continue to (1) evaluate the impact on the coal-fired facility as a whole of both ACI and enhanced ACI (e.g., corrosion); (2) assess the impact on the fly ash of the ACI or enhanced ACI with regard to its reuse and disposal; and (3) study the other atmospheric emissions that may result from use of ACI or enhanced ACI (e.g., brominated dioxins emitted either directly or formed following emission to the atmosphere). Based on these tests, on-going studies, and

discussions, we do not believe that the technologies have consistently demonstrated an ability to reduce Hg emissions by 90 percent (or any other level) for an extended period of time on all coal ranks and all boiler types. Use of sorbent injection technologies for Hg removal on European facilities is informative but does not serve to prove the technologies on U.S. facilities. We believe that the cap-and-trade approach selected for the final regulation is the best method for encouraging the continued development of these technologies. Use of sorbent injection in the IPM model served to estimate the impact of these Hg-specific control technologies in the out-years of the cap-and-trade program and was based on EPA's projections that such technologies would be available after 2010.

Comment:

One commenter (OAR-2002-0056-2929) stated that the reliable, cost-effective control technologies designed specifically for capturing Hg have not yet been fully developed or tested. EPRI, DOE, and EPA have conducted extensive research and development (R&D) programs over the past decade with the objective of developing cost-effective methods for reducing power plant Hg emissions. Mercury control technology capable of achieving high removal rates (i.e., greater than 80 percent) across the entire industry is not available. Full-scale demonstrations of Hg control technologies at individual power plants are just getting underway. It will take at least 2 or 3 years to complete these initial demonstrations and evaluate the potential effectiveness of possible new control technologies. And then, several more years will be needed before these technologies can be considered "commercially available."

One commenter (OAR-2002-0056-2160) stated that programs for testing new technologies such as ACI have been conducted for only short run times as opposed to the long running times needed to validate a technology for deployment in a power plant.

Response:

EPA concurs with this assessment of the level of demonstration of Hg-specific control technologies.

3.1.2 Mercury Control Technology Transfer from Other Industrial Sectors

Comment:

One commenter (OAR-2002-0056-3454) stated that the air pollution control industry already has considerable experience with the implementation of Hg controls for other industrial sectors. Sorbent injection has been commercially proven to augment the removal of Hg in waste-to-energy plants. Experience controlling Hg emissions has been gained in more than 60 U.S. and 120 international waste-to-energy plants which burn municipal or industrial waste or sewage sludge. For the past two decades, sorbent injection upstream of a fabric filter has been successfully used for removing Hg from flue gases from these facilities. Other reagents used include activated carbon, lignite coke, sulfur-containing chemicals, or combinations of these compounds. The Hg control experience gained from the municipal and industrial waste

combustors demonstrates that the air pollution control industry has been able to control Hg in the past and is able to apply their expertise to the electric power sector.

Response:

EPA disagrees that experience gained through use of Hg-specific control technologies on municipal waste combustors (MWC) is directly transferrable to coal-fired utility units. As noted in the proposal preamble, this results from differences in the level of Hg emissions (e.g., Hg emissions from a controlled MWC unit are roughly the same level as uncontrolled Hg emissions from a coal-fired utility unit) and differences in the species of Hg emitted (e.g., because of the Cl content of the waste stream, Hg emissions from MWC units are primarily in the oxidized form). Mercury-specific control experience in the MWC industry was the basis for initiating testing on coal-fired utility units but not as the basis for direct transfer of results.

Comment:

Several commenters (OAR-2002-0056-2867, -3478) stated that experience with application of Hg control technologies on waste incinerators cannot be applied to electric utility power plants because of process differences and differences in the fuel assays. Waste incinerators operate at much lower temperatures which are not as much of a hindrance to the Hg removal process as the higher temperatures that are typical of utility power plant systems. The waste incinerator fuel is also higher in Cl, a constituent that is associated with higher fractions of the soluble and removable form of Hg.

One commenter (OAR-2002-0056-2850) stated that although electric utilities that burn coal have measurable Hg emissions, the concentration of Hg from utilities might typically run only 1/10th that of the control limit established for incinerators. The commenter stated that this low concentration makes further Hg reductions in electric utility boiler flue gas difficult and complicates the transfer of control technologies established for other industries such as MWC to the utility sector.

Response:

EPA concurs with the commenters' assessment.

Comment:

One commenter (OR-2002-0056-4139) disagreed with the proposal preamble discussion of the differences between solid and medical waste incinerators and coal-fired utility units. The EPA stated that greater Hg reductions are achieved from the incinerators compared to utility units because of waste separation techniques. This is false because the Hg reductions are from inlet and outlet tests, independent from waste stream separation. Also, EPA's description of Hg spikes is highly unlikely. Mercury reductions of 80 to 90 percent are achieved even after good waste separation.

Response:

EPA's discussion in the proposal preamble relating to waste separation indicated that this is but one of several methods by which MWC units may achieve high levels of Hg reduction.

3.1.3 Pre-Combustion Technologies

Comment:

One commenter (OAR-2002-0056-3454) stated that with the implementation of a national program, multiple control options including pre-combustion, combustion and post combustion technologies will contribute to meeting the required emission reductions. Coal cleaning as well as coal switching are examples of options that have the potential to reduce Hg emissions prior to fuel combustion.

Response:

EPA concurs with this comment.

Comment:

One commenter (OAR-2002-0056-1817) stated that the EPA dismisses switching to lower Hg coal and any other pre-combustion controls but has no problem presenting DOE's variability analysis that assumes all plants can switch to higher Hg coal. However, KFx Corporation is currently constructing a facility for pre-combustion treatment of subbituminous coal (70 to 90 percent Hg removal).

Response:

EPA has not "dismissed" the use of fuel switching, lower-Hg coal, or any pre-combustion control technologies as compliance options. However, EPA believes that a regulation that requires a facility to switch fuels to achieve compliance results is an "unachievable" standard. We acknowledge, that some utilities will choose to switch fuels and, in fact, our IPM modeling predicts some minimal amount of fuel switching. Technologies such as that developed by KFx Corporation could be used at the discretion of the utility. With regard to the DOE variability analysis, EPA presented their analysis as being yet another approach to handling variability and sought comment. EPA used its own variability analysis.

Comment:

One commenter (OAR-2002-0056-1952) stated that studies have shown pre-combustion beneficiation of western coal, including lignite, can provide Hg reductions of up to 70 percent. Coal as-mined contains rock and minerals, and the commenter asserts that much of the Hg in coal is typically associated with these non-fuel impurities. Removal of these impurities using proven, commercial coal cleaning technology will result in greater than 60 percent Hg reduction

in many western coals. The commenter has investigated coals from the Southwest, Northern Great Plains, the Rocky Mountains, Gulf Basin, PRB, and Western Canada and states that, with the exception of the PRB, Hg reductions were substantial using simple gravity separation. The commenter stated that coal cleaning provided only a 25 percent reduction of Hg in PRB coal. Pre-combustion Hg removal should be investigated by EPA as a preferred technology for western coal; it is economical, it is proven technology, and it reduces other key pollutants such as ash, sulfur, arsenic, and NO_x. The commenter also stated that regulations that don't encourage economical pre-combustion Hg reduction will actually increase the pollution from coal-fired plants in two ways. First, there will be a disincentive to provide cleaner-burning coal fuels. Coal buyers will be attracted to cheaper, dirtier fuels. The commenter stated that if post-combustion clean-up is the only technology recognized by EPA, power plants will have higher emissions of pollutants per megawatt-hour (MWh) produced, than if policy encourages burning cleaner coal. The commenter asserts that although we may have lower Hg emissions, we'll have more solid waste, SO_2, NO_x, CO_2, and arsenic. Second, natural gas prices are unlikely to return to levels where they can provide low-cost, low-emissions electricity for the U.S. market. The commenter states that if we are to reduce emissions from the production of electricity, we must implement the most cost-effective technology available. The commenter notes that some utility clients report that post-combustion Hg removal could add $8 to $12 per ton to the cost of using coal. The commenter states that those costs will be directly absorbed by U.S. industry, impacting American products and services from aluminum to computer server farms.

One commenter (OAR-2002-0056-3478) stated that fuel processing technologies are being developed to remove Hg and sulfur from the coal before it reaches the plant. Washing coal is one method that has been used on the higher rank coals for some time. Processes are being developed for low rank coals such as lignite that have the potential of reducing, or perhaps eliminating, the requirement for post combustion equipment. Some technologies incorporate novel ways of physical screening while others involve heat and pressure to drive off pollutants. Additional work will be required on coal treatment processes to complete the economics of these processes. Also, in fuel processing, it may not be practical to treat all of the coal going to a plant because of the large amount of tonnage involved. The commenter believes the economics of coal treatment systems would be greatly enhanced if it were possible to treat only a fraction of the total tonnage consumed by a unit.

Response:

Utility units are free to utilize any means available, including pre-combustion treatments, to achieve compliance with the standards.

3.1.4 Combustion Technologies

Comment:

One commenter (OAR-2002-0056-2922) stated that the single Hg combustion technology that has been investigated to control Hg has been demonstrated only on a pilot scale without

full-scale applications. A Hg control combustion practice has been investigated by GE-EER on a pilot-scale combustor that is several orders of magnitude smaller than a utility boiler. Essentially, the technique achieves high loss on ignition (LOI) by combusting the fuel initially at low oxygen concentrations to promote the formation of carbon in the boiler and the fly ash. GE-EER primarily evaluated the Hg removal potential for low-rank coals such as PRB and lignite. The vendor claims Hg removal rates of up to 40 percent for low-rank coals, although its own data seem to indicate that only 25 percent removals were actually achieved. This technology goes against the trend in the utility industry whereby burner manufacturers for years have been trying to minimize LOI to address the concern of the utility industry that high carbon levels make it impossible to sell fly ash as an additive to cement. Although the GE-EER "in-situ" carbon formation concept for Hg removal results looks interesting, it is far from being a commercial process. At this stage of development it is impossible to evaluate its true costs. For example, costs cannot be evaluated without knowing the extent to which this technology would result in lost income from the inability to sell fly ash with high LOI levels and increased disposal costs of up to $30 to $40 per ton for fly ash. Finally, this technology might cause the radiant and convective boiler section tubes to be blanketed with carbon, decreasing boiler efficiency and increasing the cost of electric production.

Response:

EPA is not mandating use of any technology to achieve compliance with the final rule. The industry is free to use any means, including the one cited by the commenter, to achieve compliance with the standards.

Comment:

One commenter (OAR-2002-0056-2889) stated that EPA did not adequately consider low-NO_x burners as a Hg control technology. The EPA wrongly characterized this system as poor tuning (69 FR 12402). Low-NO_x burners result in higher levels of unburned carbon in coal ash, and are a mature technology required in the Northeast for years to achieve the NO_x RACT. In Massachusetts, units at the Salem Harbor and Mt. Tom Station power plants are averaging 83 to 87 percent Hg capture in coal using low-NO_x burners and ESP units. The EPA should recognize the possible role of low NO_x burners in helping reduce Hg emissions.

One commenter (OAR-2002-0056-3449) stated that the best Hg control technology for existing coal-fired power plants is use of fabric filters with low-NO_x burners. Rather than injecting carbon like ACI, the low-NO_X burners tend to generate carbon that is caught by the bags and then may absorb Hg. Controls in use today at power plants in New Jersey to reduce emissions of SO_2 and PM have achieved Hg reductions of 90 percent or more (scrubbers and fabric filters with low-NO_x burners and SCR for NO_x).

Response:

EPA's description of "poorly tuned coal burners" in the supplemental notice did not refer to properly installed and operated low-NO_x burners as the commenter states. Rather, the

discussion was directed at any type of burner that had not been properly maintained and operated. Low-NO_x burners are in wide-spread use in the coal-fired utility sector and could be a part of any utility's compliance strategy. EPA notes, however, that use of low-NO_x burners on low-rank coals is unlikely to result in significant Hg capture due to the low levels of chlorine in the coal.

3.1.5 Post-Combustion Technologies

3.1.5.1 General Comments on Hg Control Performance

Comment:

Many commenters stated that coal plants can achieve greater than 90 percent Hg control using existing technology which is available at many plants (e.g., scrubbers, fabric filters, and SCR) or by ACI. ACI is commercially available today and technology transfer from MWC units is clearly feasible. Municipal waste combustors with fabric filters and ACI have achieved 99 percent Hg control; DOE analyses show that retrofitting a coal-fired boiler with ACI and fabric filter also can achieve 90 percent control with low capital and operating costs.

Many commenters also stated that the emission reductions used by EPA are much too low compared to what is technically achievable and cost effective. Based on currently available control technology, existing units should be able to meet at least 80 percent Hg efficiency for subbituminous coal and a minimum of 90 percent for bituminous coal.

Response:

EPA agrees that some coal-fired units have exhibited greater than 90 percent Hg reductions in the limited test data available. However, not all units have been able to achieve this level of control, even with similar control technologies installed. As noted earlier, EPA disagrees with the commenter's assessment regarding the commercial availability of Hg-specific control technologies and on the ability to transfer the technology from the MWC industry.

Comment:

One commenter (OAR-2002-0056-3210) stated that based on the ICR III data, the best reductions for Hg and sulfur an be achieved with wet scrubbers and fabric filters or spray dryer absorbers with fabric filters. Analysis of the data showed that in the 8 states surrounding New York, fabric filters achieved the best control of Hg, followed by an ESP with wet scrubbers. Municipal waste combustors in New York using ACI with fabric filters achieve 90 percent Hg reduction while combustors with ACI and an ESP achieve at least 85 percent reduction.

Response:

EPA is charged with establishing a standard that is achievable nationwide, not just in one sector of the nation. As noted elsewhere in this document, EPA has reanalyzed the available

data and revised the new-source NSPS limits based, in part, on the control technologies suggested by the commenter.

Comment:

One commenter (OAR-2002-0056-4209) agrees that optimizing controls for NO_x and SO_2 can reduce Hg from 60 to over 90 percent.

Response:

EPA agrees that existing controls can be optimized for Hg removal and believes that the approach taken for the final rule will provide the greatest incentive to induce early applications of such optimization.

Comment:

One commenter (OAR-2002-0056-2661) stated that there are inherent problems in a Hg control philosophy based on Hg control technologies that require converting elemental Hg to a form potentially more harmful to human health for the purpose of Hg emission control efficiency. It doesn't make sense to require the formation of a potentially more harmful species of Hg in order to remove it from the flue gas stream.

Response:

EPA has no information to indicate that oxidized Hg is any more harmful to human health than is the elemental form, particularly at the concentrations found in the atmosphere (i.e., the levels found in the atmosphere are significantly lower than those expected from a Hg spill in a confined space). Oxidized Hg would tend to deposit closer to the emission source than elemental Hg, but elemental Hg is ultimately transformed to oxidized Hg forms in the atmosphere and subsequently deposited. Oxidizing the elemental form enhances the ability of many control technologies to remove significant levels of Hg from the exhaust-gas stream. EPA believes that the rule will reduce the risks from Hg, rather than increase them.

Comment:

One commenter (OAR-2002-0056-2422) stated that the EPA paper, "Control of Mercury Emissions from Coal-Fired Electric Utility Boilers," presents a narrow and misleading view of the Hg capture performance of conventional SO_2 and particulate control technologies. If the purpose of the paper was to communicate what is and is not known about Hg control, the paper should have discussed the limitations of the data from which conclusions were drawn, the variability and uncertainty of the results in that data, the performance that can be expected over a range of coal ranks, the confidence intervals for those estimates, and what EPA is doing to improve the state of knowledge on the effectiveness of conventional as well as advanced control systems.

Response:

The referenced paper was written in late 2003 and was based on data available at that time on Hg capture performance of conventional SO_2 and particulate control technologies. The paper was intended to provide a brief overview of the state of Hg controls for Hg emissions from coal-fired utility boilers and it was not intended to provide a detailed statistical analysis of the available data. Such analyses of Information Collection Request (ICR) data have been conducted by EPA and are in the docket. The paper does briefly discuss results obtained from the ICR data. However, that data represented a wide range of combinations of boilers, coal types, and air pollution control configurations. As mentioned in the referenced paper, and elsewhere, the ability to capture Hg in the PM or SO_2 control device is highly dependent upon the form (elemental, oxidized, or particulate-bound) of the Hg. The form of Hg in the flue gas is dependent upon the type of coal being burned, the combustion conditions, and the installed air pollution control configuration. The paper does discuss the variability resulting from interactions of these many combinations. For example, on page 7, the final paragraph of the referenced paper notes that the "ICR data reflected that average Hg captures ranged from 29 percent for on PC-fired ESP plus flue gas desulfurization (FGD) unit burning subbituminous coal to 98 percent in a PC-fired FF plus FGD unit burning bituminous coals."

Comment:

One commenter (OAR-2002-0056-2843) stated that implementation of the proposed standards would require new plants to comply with levels of Hg emissions that are inconsistent with available demonstrated technology. The commenter stated that there are no creditworthy suppliers of Hg control technology in a position to provide guarantees of performance consistent with the levels required under the rulemaking. Absent such technology guarantees of performance, the commenter submits that only a small portion of the available coal resources in the U.S., particularly those in the PRB in Montana and Wyoming, are known to have Hg content sufficiently low as to permit operation in conjunction with commercially available air pollution control device technologies, such as fabric filters, to meet the requirements of the rulemaking. The commenter cites for example, only about 8 percent of PRB subbituminous coal reserves would qualify as "compliance coal" if the "new source" criteria proposed by the EPA is adopted.

Response:

As noted later in this document, EPA has reanalyzed its new-source NSPS limits.

3.1.5.2 Fabric Filter Hg Control Performance

Comment:

One commenter (OAR-2002-0056-2359) stated that fabric filter technology exists today that can reduce Hg emissions by 72 percent on average for subbituminous coal and up to 92 percent for bituminous coal. Activated carbon injection is very cost effective and in the early stages of full scale commercialization. The combination of ACI and fabric filters essentially

eliminate problems with carbon contamination of fly ash and would allow for the beneficial reuse of ash in concrete and other products.

Response:

As noted above, EPA disagrees on the degree of commercial availability level of ACI. In addition, as noted later in this document, EPA has reanalyzed its new-source NSPS limits. EPA agrees that the use of a supplemental fabric filter with ACI will allow for the beneficial reuse of fly ash.

3.1.5.3 ESP Hg Control Performance

Comment:

One commenter (OAR-2002-0056-2259) stated that the his company installed in 2001 a pilot-scale wet ESP at FirstEnergy's Penn Power's Bruce Mansfield Plant located in Shippingport, PA. The ESP uses a slipstream of flue gas from the exhaust of the FGD system on boiler unit No.2, which has a rated capacity of 835 MW and burns 3 percent sulfur coal. The plant installed the pilot ESP to test for PM2.5 and $S0_3$ mist removal as a potential control technology to reduce visible emissions. Further Hg testing was performed during 2003 under an award from DOE's National Energy Technology Laboratory. The tests confirm that wet ESP technology can collect $PM_{2.5}$ and sulfuric acid (SO_3) mist as well as Hg at very high levels. Particulate and oxidized Hg species were collected with greater than 70 percent efficiency while elemental Hg can be partially oxidized, in the range of 18 percent to 44 percent. Successful development of the Plasma-ESP technology will also allow for high removal efficiency of elemental Hg within the wet ESP. Therefore, wet ESP technology should be given consideration as another control technique that offers the co-benefits of capturing $PM_{2.5}$ and SO_3 with little pressure drop (< 1 inch water column), low power consumption (1 kW/MW). and no additional real estate if mounted on top of the FGD system or retrofitted within a dry ESP.

One commenter (OAR-2002-0056-1842) stated that the Croll Reynolds' Plasma Enhanced ESP technology (PEESPTM) is to be installed at Southern Company's Miller plant. In this pilot, a 5,000 actual cubic foot per minute (acfm) wet ESP will be installed after a dry ESP to test for $PM_{2.5}$ and SO_3 and Hg removal under a EPRI funded contract. It will operate in an unsaturated flue gas environment and will incorporate the PEESPTM technology, which at lab scale has demonstrated up to 79 percent elemental Hg control. Buzz Reynolds says that successful demonstration of the Hybrid dry-wet ESP with PEESPTM could offer plants burning low sulfur coals a cost-effective option to that of injecting activated carbon followed by fabric filter. Croll Reynolds claims that the wet ESP approach adds less than one-half inch pressure drop, requires no additional real estate if retrofitted into the last field of the dry ESP, operates at low power (1 kW/l MW), has no impact on the dry ESP fly ash, and minimizes the handling of the waste by-product by concentrating the Hg in the WESP slurry, which is then treated in a recycle system where the Hg is precipitated out of the water. The Hg by-product is in a much more concentrated, compact form for easier disposal and handling.

Response:

EPA is not mandating use of any technology to achieve compliance with the final rule. The industry is free to use any means, including the one cited by the commenters, to achieve compliance with the standards.

Comment:

One commenter (OAR-2002-0056-2889) stated that a statement by DOE in a Hg control technology R&D fact sheet wrongly dismisses the high Hg capture efficiency achieved at Brayton Point as an "unusual ESP configuration." A more appropriate reaction is that an ESP can be used with ACI to achieve high Hg removal rates. Salem Harbor's 90 percent Hg removal rate is also portrayed as unusual even though the State has other units with similar particulate-bound Hg fractions. DOE's characterization only serves to promote as lenient a control level as possible rather than building on the strong successes their funding helped document.

Response:

EPA concurs that ESP units may be used with ACI under the proper conditions to effect Hg removal.

3.1.5.4 Wet Scrubber Hg Control Performance

Comment:

One commenter (OAR-2002-0056-3478) stated that enhancing gas phase oxidation systems warrant further investigation to reduce Hg. The term "gas phase oxidation systems" refers to the process of improving the ability of a scrubber to capture Hg by using a technology to oxidize the Hg. Compounds that are water-soluble are "scrubbed" or removed from the flue gas into the scrubbing liquid and removed with the scrubber sludge. Thus, an existing FGD system has the ability to remove the fraction of the Hg that is oxidized.

Response:

Systems such as the one the commenter describes are included in the DOE program and, if proved successful, would be available as compliance options by industry should they so choose.

3.1.5.5 Sorbent Injection for Hg Control

Comment:

Several commenters (OAR-2002-0056-2871, -2889) stated that ACI is commercially available and widely recognized as a viable control for Hg. It has been demonstrated with pilot

and full-scale demonstration projects on coal and has been used for over 10 years on other large combustion projects. States are now requiring it on new coal-fired units for Hg control. The EPA's failure to consider this technology is inconsistent with its past approaches for developing Hg limit for combustion sources and EPA provides no justification for the change. In previous standards, EPA has not required technologies to be in long-term us to be considered "commercially available" and to be evaluated as a potential control method. For example, EPA proposed NSPS and emission guidelines for MWC units that require ACI even though it had been tested at only two facilities (and went beyond the floor because lower emissions were achievable at low costs). The EPA also evaluated ACI for hazardous waste and medical waste incinerators, even though the technology was rarely used. Sorbent injection technologies such as ACI have been demonstrated to achieve significant Hg reductions at coal-fired power plants regardless of coal type; Hg control above 90 percent is feasible at costs similar to those for NO_x removal (Mercury Emissions from Coal Fired Power Plants, NESCAUM, October 2003). State and local agencies are using these studies to establish permit limits for new boilers. Wisconsin is preparing to permit a coal-fired unit using subbituminous coal at 83 percent control efficiency for Hg (Wisconsin Public Service Company Weston Unit 4). Iowa has issued a permit for a facility using subbituminous coal requiring 1.7 lb Hg/TBtu (equivalent to an 83 percent control efficiency for operation with coal from the source with the highest average Hg content (MidAmerican Energy Company Council Bluffs Energy Center). One of these units has commenced construction under that permit. Therefore, the technology is in commercial use and must be considered in the development of performance standards.

One commenter (OAR-2002-0056-3454) stated that Hg specific control technologies such as sorbent injection systems have been demonstrated at full-scale. Multi-pollutant control approaches as well as other Hg specific technologies have also demonstrated significant progress and will provide additional low cost, innovative approaches to Hg control. A number of these technologies, including sorbent injection systems as well as SCR coupled with wet FGD, have achieved removal rates greater than 90 percent under certain circumstances.

One commenter (OAR-2002-0056-3449) disagreed that there are no commercially available control technologies specifically designed for reducing Hg emissions as the EPA stated in the rationale for the proposed subpart Da standards (p. 4691). Activated carbon injection is commercially available today for Hg control. Ten years of experience with ACI on MWC incinerators in New Jersey show that technology transfer is feasible. Some of these incinerators achieve 99 percent Hg control with fabric filters. The EPA is mistaken to discount ACI because it has only been pilot tested or short term demonstration tested at full scale units, and has not been in long term use at any coal units. It will be used long term if required. The NESCAUM report on full-scale demonstration of ACI shows that 90 percent Hg removal is feasible with costs comparable to NO_x removal. A recently issued Iowa permit requires ACI from a proposed bituminous coal plant. DOE pilot studies show up to 95 percent control for both bituminous and subbituminous control with fabric filter and ACI. National Energy and Gas Transmission Company's Carneys Point and Logan Township boilers are each equipped with low-NO_x burners, SCR, dry scrubber, and fabric filter which reduce Hg emissions by more than 90 percent.

One commenter (OAR-2002-0056-3205) stated sorbent injection is available for the control of Hg emissions. Activated carbon injection has been used successfully on MWC units for the past 7 to 8 years and the technology has been successfully demonstrated in several full-scale tests, including the recent year-long test at Gaston. Vendors such as ADA-ES have indicated that ACI is available now for utility units. The commenter also refers to an Iowa permit requiring ACI at a new MidAmerican Energy Council Bluffs plant. Xcel also proposes to use ACI at a new unit at the Comanche plant. The commenter referred to the definition of available technology in EPA's new source review workshop manual ..."a technology is considered available if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term." Activated carbon injection has clearly reached the commercial availability stage for utility units.

One commenter (OAR-2002-0056-2819) stated that ACI is one of several commercially available, cost effective technologies for coal-fired boilers. Activated carbon injection systems are commercially available and have been install on MWC units. Others include wet ESP, fly ash injection systems, SCR, wet and dry FGD system, and fabric filters. West ESP and fly ash injection systems are already in use on coal-fired boilers in the U.S., Europe, and Japan. This data was presented to EPA. Wet ESP, fly ash injection systems, SCR, wet and dry FGD systems, and fabric filters have been commercially available and installed on coal and oil-fired utility boilers for many years.

Several commenters (OAR-2002-0056-2873, -3210) stated that full-scale demonstration projects have been conducted and are on-going at many U.S. coal-fired power plants to test the effectiveness of ACI with conventional PM controls for control of Hg emissions. According to the commenters, these full-scale ACI demonstrations so far have demonstrated at least 50 percent Hg removal and those with pre-halogenated sorbents have observed as much as 95 percent. The E.C. Gaston plant burning low sulfur bituminous coal achieved 90 percent removal using carbon injection with a hotside ESP and COHPAC fabric filter. The Brayton Point plant burning low sulfur bituminous coal achieved 90 percent with carbon injection and a coldside ESP. The Pleasant Prairie plant burning subbituminous coal achieved 65 percent using ACI with a coldside ESP. Gaston showed that a high removal rate using significantly less ACI can be achieved with the COHPAC system in comparison to other conventional controls. The controls apply to bituminous and subbituminous coal.

One commenter (OAR-2002-0056-2575) stated that the EPA improperly rejected ACI or sorbent injection systems as viable Hg control technologies. Much research shows that these systems are highly effective (80 to 90 percent Hg removal). EPA claims that carbon-based and sorbent injection control systems are not currently available on a commercial basis. However, in a separate discussion of certain carbon-based injection system, the EPA repeatedly describes them as commercially available. The EPA also rejects injection-based systems because they have not been installed except on a demonstration basis and no long-term data are available to indicate performance on all representative coal ranks. EPA's refusal is a direct violation of the CAA goals. The legislative history clearly shows that Congress intended the statute to be technology-forcing. EPA's agreement that it cannot force the industry to implement specific controls until the industry has fully implemented the same controls is circular logic and destroys

any incentive for industry to develop better controls.

One commenter (OAR-2002-0056-2199) stated that a 90 percent Hg reduction using ACI is feasible based on a 2002 technical report by the Massachusetts Department of Environmental Protection. Also, DOE tests at an Alabama plant found that ACI achieved 90 percent Hg reduction at a very low cost (0.05 cents/KWh). Preliminary tests with ACI by EPRI achieved 90 percent with eastern coal ranks and 60 to 70 percent with western coal ranks at costs from 0.2-0.3 cents/KWh.

Response:

As noted earlier, EPA disagrees with the commenters about the availability of Hg-specific control technologies at the present time. The limited, but increasing, number of tests have not yet brought the technologies to the level of demonstration that we feel necessary to be considered "commercially available" and the basis for a national standard for this industry. We do not believe that these technologies are available now for wide-spread usage. We have been following the studies of such technologies closely and have discussed their degree of development with vendors, the industry, and the DOE. No utility unit has operated a Hg-specific control technology full-scale for longer than a month or so. Based on these tests and discussions, we do not believe that the technologies have demonstrated an ability to reduce Hg emissions by 90 percent (or any other level) for an extended period of time on all coal ranks and all boiler types. We believe that the cap-and-trade approach selected for the final regulation is the best method for encouraging the continued development of these technologies.

Comment:

One commenter (OAR-2002-0056-1842) stated that sodium tetrasulfide (Na_2S_4) technology can remove elemental as well as ionic (oxidized) forms of Hg. Other advantages include: the fact that it results in an inert, stable reaction product (cinnabar). Sodium tetrasulfide is a liquid, and, thus, is easier and safer to handle and inject than powdered activated carbon and is less abrasive than activated carbon. Both full scale and pilot plant tests have demonstrated that the Na_2S_4 process is both a technologically and an economically effective approach to controlling Hg emissions on MWC units. Pilot plant and short-term tests have verified that the Na_2S_4 technology alone or in combination with activated carbon technologies can achieve a controlled Hg emission rate approaching the expected regulatory requirements for coal-fired boilers. Longer test programs are planned to optimize the flue gas temperature regime and Na_2S_4 dose rate. Because the efficiency of the Na_2S_4 process is influenced by mass transfer rates, the technology may be most effective on facilities equipped with fabric filters and wet FGD systems due to the additional retention and contact time.

Response:

EPA is not mandating use of any technology to achieve compliance with the final rule. The industry is free to use any means, including the one cited by the commenter, to achieve compliance with the standards.

Comment:

Several commenters (OAR-2002-0056-2887, -2946) stated that in the proposal notice (69 FR 4674) the EPA presented a misleading characterization of conclusions from the NESCAUM October 2003 report "Mercury Emissions from Coal Fired Power Plants." The NESCAUM analyses show that commercially available control technologies, as well as rapidly emerging technologies, are capable of achieving greater than 90 percent Hg control. Activated carbon injection has been used on MWC units for 5 to 10 years, are routinely achieving greater than 90 percent Hg control, and has been successfully demonstrated on coal-fired electric utility generating units by DOE. The commenters requested that the EPA correct the preamble statements to reflect the actual conclusions of the report.

Response:

As noted elsewhere, EPA disagrees with the commenter on the availability and level of Hg reduction achievable by ACI. We apologize for any misleading characterization of the NESCAUM report in the proposal preamble.

Comment:

One commenter (OAR-2002-0056-3478) stated that ACI is not a one-size-fits all control technology; it is highly dependent upon boiler exhaust temperatures, and works best at temperatures below 300 °F. Because the commenter's coal-fired boilers experience exhaust temperatures in excess of 350 °F to over 400 °F, the overall removal efficiency of vapor phase Hg by ACI would be significantly decreased. The commenter states that to achieve a desired removal rate with the higher back-end temperatures will require significantly more activated carbon to be injected. The commenter adds that recent pilot scale testing indicates that ACI may not be effective at all at temperatures of 400 °F or above.

Response:

EPA is aware of the concerns expressed by the commenter. It is concerns such as these that factor into the Agency's decision that ACI is not yet a commercially available technology ready for universal, wide-spread usage.

Comment:

One commenter (OAR-2002-0056-3478) stated that ACI is already used in water and wastewater applications, and it is not clear that a new significant demand in production for use in ACI controls at coal-fired power plants could be met. The commenter added that the added demand will increase the price of activated carbon, changing the cost effectiveness of this technology.

Response:

EPA also has concerns about the short-term availability of activated carbons suitable for wide-spread usage by the coal-fired utility industry.

3.1.5.6 Other Hg Control Technologies

Comment:

One commenter (OAR-2002-0056-1842) listed a number of Hg control technologies under various stages of development that should be considered by the EPA as Hg control options. These included the following. Powerspan has a 50 MWe commercial demonstration unit of electro-catalytic oxidation (ECO) technology at the FirstEnergy R.E. Burger plant. The Mitsui BF activated coke system is used in full-scale installations on combustion sources in Japan. The Kentucky Utilities Ghent generating station is the host of a 5 MW slipstream demonstration of the Airborne process being developed by Babcock & Wilcox and US Filter HPD systems. The EPRI and Apogee Scientific have been developing a Hg control technology called MerCAP (Mercury Control via Amalgamation Process). ADA Technologies, Inc. and CH2M-Hill are developing a new family of Hg sorbents, called Amended Silicates™. Nooter Eriksen and EnviroScrub are offering the Pahlman technology with multi-pollutant control capabilities including Hg removal.

One commenter (OAR-2002-0056-5316) stated that the Toxecon II™ technology is applicable to 715 coal-fired plants while the new high temperature sorbents cover another 82 plants. The industry can reach a 70 percent Hg removal rate by 2010 and 90 percent by 2014 with this technology. The Toxecon II™ system can be rapidly deployed because it takes advantage of the existing ESP. It is cost effective because the new chemically-enhanced AC sorbent has low injection rates. In addition, the plant can continue to sell 90 percent of its fly ash for use in concrete.

Response:

EPA is aware of these technologies and aware that none are in full-scale application. We believe that the final rule's cap-and-trade approach, with declining caps and market rewards for reductions will provide the impetus necessary to bring these technologies to full development.

3.1.5.7 Impact of Coal Chlorine Content on Hg Control Performance

Comment:

One commenter (OAR-2002-0056-2422) stated that the best performing technologies for Hg removal are fabric filters (with or without scrubbing) and wet scrubbers with (cold- or hot-side) ESP units. The Hg removal capability of these technologies is found to be correlated with coal Cl content. The performance of these control technologies is substantially reduced and

highly variable when firing coals with low Cl content. Thus, there is not have a high level of confidence that the best performing technologies will reduce Hg emissions to a significant degree when units fire coals of relatively low Cl content. The performance of other emission control technologies does not appear to be sensitive to Cl content.

Response:

EPA has based its emission limits on the performance of technologies within each of the subcategories and, thus, feels the situation noted by the commenter has been addressed.

Comment:

One commenter (OAR-2002-0056-1842) stated that the addition of a chloride pre-scrubber before a SO_2 wet scrubber should ensure 90 percent Hg removal and even more. A number of European waste-to-energy plants utilize this technology and achieve 90 percent removal (combination of pre-scrubber and scrubber). There is no reason this technology needs to be modified for coal-fired power plant use. The chloride pre-scrubber levels the playing field for those burning PRB coal. No matter how small the Cl content of the coal, the pre-scrubber captures it as hydrochloric acid and then builds the concentration to the needed level. The chloride scrubber by itself should provide all the oxidation necessary. But if higher oxidation is still desired, you can deposit some of the salts or the acid back on the coal feed belt. So the concern that low sulfur, low Cl coals will make it more difficult to remove Hg is eliminated with this scheme.

Response:

EPA is not mandating use of any technology to achieve compliance with the final rule. The industry is free to use any means, including the one cited by the commenter, to achieve compliance with the standards.

Comment:

One commenter (OAR-2002-0056-3517) stated that EPA has hypothesized that Hg removal rates are influenced by the amount of Cl that is contained in the coal. The commenter notes that although western bituminous coals are low in Hg content relative to other coals, they are also very low in Cl. The commenter adds that there is evidence that these coals perform very well with current technology in reducing Hg, despite the low Cl content. According to the commenter, a case in point is the Intermountain Plant in Utah, which burns a low Hg, low Cl Utah bituminous coal; it is possible that the Cl content may be a surrogate for other factors that influence Hg reduction performance.

Response:

EPA believes that the Cl content is but one of many factors that may impact on Hg removal from coal-fired utility units. The performance of western bituminous coals noted by the

commenter is one factor that lead EPA to subcategorize all bituminous coals together.

Comment:

One commenter (OAR-2002-0056-2944) stated that the different average Cl levels of the different coal ranks was used as the justification to support proposing different emission limits and allocation weightings. However, based on the commenter's analysis, Cl is found to be of little importance. The utility industry is already removing about 30 percent of the estimated 75 tons of Hg coming into its plants annually with the fuel. The commenter further stated that according to ICR flue gas measurements, this Hg is primarily removed at bituminous coal plants as soluble oxidized Hg (due to coal Cl) in existing SO_2 scrubbers and as absorbed oxidized and elemental Hg on unburned carbon captured in the plants' particulate collectors (due not to higher Cl in bituminous coal, but due to their higher unburned carbon levels, which result from less-reactive fly ash). (The commenter notes however, that only 20 percent of U.S. boilers have scrubbers.) The commenter states that as indicated in the second Hg-content plot (see OAR-2002-0056-2944), if all the bituminous coals are adjusted for a 30 percent (post-combustion) reduction in their Hg levels, and subbituminous coals see no corresponding reduction, the Hg (emission) distributions for these two fuels, which encompass over 95 percent of U.S. coal use, are amazingly identical. Therefore, when considering coal Hg, Cl, and fly ash together, without any specifically-added Hg control technology, subbituminous coals are currently not at any disadvantage relative to bituminous coals with respect to Hg emission limits.

Response:

EPA is not alone in its belief that the Cl content of coal is a factor in the level of Hg removal achievable. It is also realized that the level of unburned carbon in the exhaust gas is also a contributing factor. We believe that the final rule does not disadvantage any coal rank.

3.1.5.8 Impact of SCR for NO_x Control on Hg Control Performance

Comment:

Several commenters (OAR-2002-0056-1969, -2830) disagreed with EPA's statement in the proposal preamble that although no full-scale lignite-fired SCR-equipped unit has been tested for Hg removal it is possible that greater Hg removal would result when an SCR unit was applied to a lignite-fired unit. The commenters stated that testing of a pilot-scale SCR reactor at Coyote Station (a nominal 420 MWe lignite-fired generating facility that is located near Beulah, North Dakota) showed that the SCR technology is ineffective in oxidizing Hg and that the saltation of calcium and sodium ash deposits foul the catalyst rendering the SCR technology ineffective for NO_x control. The installation was in conjunction with a study entitled "Impact of SCR Catalyst on Mercury Oxidation in Lignite-Fired Combustion Systems" that conducted by the Energy and Environmental Research Center located in Grand Forks, North Dakota.

One commenter (OAR-2002-0056-3514) stated that currently, no technology has been shown to be effective in capturing Hg from lignite coals. Lignite and other low-rank western

coals face additional obstacles that do not affect other ranks of coals, specifically higher ash, lower Cl, and higher elemental Hg content. According to the commenter, these factors make it impossible, at least currently, to attain the removal percentages being achieved with other coals. The commenter noted that EPA refers to SCR, intended for NO_x reduction, as an option that could also significantly increase the oxidation of Hg in the flue gas to improve capture. The commenter stated that although this may have been shown to work for certain coal ranks, it has been shown that the SCR blinds almost immediately in lignite applications in recent large scale testing conducted by the University of North Dakota Energy and Environmental Research Center. Thus, in establishing Hg removal goals and limits, the commenter believes EPA must consider that SCR is not a viable option for lignite.

Response:

EPA still believes that SCR installations on lignite-fired units will, with further development, provide improved Hg removal. Any improvement will provide yet another means for such units to effect compliance with the final rule. However, the use of SCR units on lignite-fired units was not included in the analyses that led to the final emission limits for this subcategory.

3.1.6 Analysis of ICR Hg Emission Data

Comment:

Many commenters (OAR-2002-0056-1675, -1677, -1680, -1692, -1762, -2160, -2422, -2535, -2818, -2876, -3198, -3478, -3534, -3565) stated that the ICR Part III data are not appropriate for establishing any regulatory standard because of the deficiencies in the quantity, quality, and accuracy of this data set. Reasons cited by commenters include the following. The ICR emissions data fail to meet generally accepted limits of experimental accuracy and precision. The data set includes estimates of negative Hg removal, incomplete data, failure to close the material balance in the overall accounting for Hg input and output, and low precision. The 80-plant ICR sample data provide an unrepresentative snapshot of emissions from a limited number of facilities because the data include emissions from the use of a limited number of fuel types over a limited period of time. The wide variability of coals and process conditions is not accounted for in the ICR sample data. The units chosen by EPA for Hg emissions sampling in the ICR program are unrepresentative of the coal-fired power plants in the U.S. The companies that performed the tests had inadequate experience with the required test methodology. The data are affected by a bias in testing conditions, because the testing was done during high-load and steady-state operations. The data were gathered using a test method that is very different from what is proposed for compliance demonstration under the rule and no effort has been made to translate the proposed standards that were developed from the data to the basis of the test methods proposed for compliance demonstration. The reported coal rank used to classify some of the units tested was incorrect or did not accurately reflect the blending of coals from different ranks. The selection of the units chosen by the EPA for testing is skewed toward wet- and dry-scrubbed units which are more likely to show lower emissions than the majority of plants, which are inscribed.

In contrast, Commenter OAR-2002-0056-5535 stated that EPA's ICR III dataset is more than adequate to support establishment of stringent standards. The industry commenters opposing the ICR data set identify nothing in the language of the CAA that requires that the dataset comprehensively account for emissions information from the industry as a whole, provided the data allow EPA to make a reasonable estimate of performance of the top 12 percent of units. (Sierra Club v. EPA, 167 F.3d 658, 662 (D.C. Cir. 1999). The D.C. Circuit has further observed that EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. (Cement Kiln Recycling Coalition v. EPA, 255 F.3d 855, 867 (D.C. Cir. 2001) ("CKRC") (quoting Sierra Club, 167 F.3d at 662)). It is only when the model or dataset chosen bears "no rational relationship to the reality it purports to represent" that a court will interfere with the agency's exercise of its discretion. (Columbia Falls Aluminum Co. v. EPA, 139 F.3d 914,923 (D.C. Cir. 1998)). Putting aside the legal requirements, EPA also thoroughly debunked the factual basis underlying the industry claims that the ICR database is too weak to use for standard-setting. Industry stakeholders first raised this issue in 2001 during the Utility Working Group process. At that time, EPA presented their analysis of both the coal sampling data and the emissions testing data. With respect to the fuel analyses, EPA concluded that the "data are sufficient to use in the development of MACT standards." For the emissions tests, the agency undertook what they described as an "[e]xtensive quality assurance effort." After examining individual test data, excluding invalid data and examining data points for potential outliers, EPA found no reason to exclude any of the complete datasets as outliers. As with the fuel analyses, EPA concluded the "[s] tack test analyses data are sufficient to use in the development of MACT standards."

Response:

EPA believes that the data are adequate with which to establish appropriate emission limits for the industry. EPA agrees with some of the comments made but not with the conclusions. For example, EPA made no attempt to conduct a material balance around the utility unit, this not being necessary to establish an emission standard. Units showing negative removals are, obviously, not among the better controlled units and, thus, were not used in establishing the emission limit. The 80 units tested, although seemingly limited in number, represent a larger data set than available for other CAA section 111 or section 112 regulatory efforts. The matrix of unit types to be tested was subject to public notice and comment prior to being sent to the industry. The resulting mix and number of units is a compromise between the greater number of units that could have been tested as inferred by the commenters and the cost of such testing. EPA reported the rank of coal used during the testing based on what the companies involved provided to EPA. EPA did not specify the load to be maintained during testing but concurs that testing of this type is generally undertaken during periods of steady-state operation to minimize the problems associated with evaluating test results obtained during periods of fluctuating operation. However, we feel that the incorporation of variability in the analyses adequately addresses this issue. The testing runs were conducted sequentially, so source variation in emissions is present from run to run. Therefore, no measurement of sampling precision is possible as this would have required the use of paired sampling trains at all sites. The test contractors utilized by the industry are among those regularly employed in such activities and, thus, are familiar with both the industry as well as the various EPA

Reference Methods. The Ontario-Hydro method used, although requiring attention to the details of the procedures, utilizes much of the same sampling equipment as does other EPA Reference Methods more widely utilized by the test contractors. Further, attention to the details of the test methodology is not, or should not be, anything different from such contractor's performance of any emissions test. The proposed continuous Hg measurements are for gaseous Hg only; most of the Hg measured through the Ontario-Hydro method was also determined to be gaseous. EPA performed some comparisons of the data obtained through manual vs. continuous monitoring for those sites at which the continuous monitors were evaluated and believes that the 12-month rolling average format chosen adequately reflects an appropriate translation of the data.

Comment:

One commenter (OAR-2002-0056-2535) retested in 2003 some of the power plants burning Wyoming PRB coal included in the ICR Part III data sets. The re-testing methods used at these plants were consistent with the methodologies and protocols used in the EPA ICR III testing. Irrespective of the distribution of the Hg species at the APCD inlet, the outlet stream contains mostly elemental Hg. Both the ICR and the newly acquired data are directionally consistent but have significant variation due to coal Hg content and operational variability. This corroborates the earlier observations that data variability is an issue. Hence, any regulatory standards or guidelines must account for the variability, specifically in the case of subbituminous coal due to its higher fraction of elemental Hg exiting the furnace.

Response:

EPA concurs that variability must be accounted for in any emission limits. We believe that the final emission limits adequately address the commenter's concerns.

Comment:

One commenter (OAR-2002-0056-3560) stated the ICR data collection effort appears to have been done on a dry basis. This introduces minor error when the actual testing is done including moisture on an as-received basis, but the impact on the regulation in lb/MWh may be more significant. This issue has not been addressed by EPA.

Response:

EPA provided the data on a dry basis for consistency and ease of use of the data because some data were reported by the companies on a wet basis and some on a dry basis. We do not believe that this will have a significant impact on the rulemaking.

Comment:

One commenter (OAR-2002-0056-2422) stated that based on the commenter's analysis of the ICR Part III data, no statistically significant differences can be detected in the Hg removal performance among the three configurations of fabric filter controls alone or combined with wet

or dry scrubbers. Similarly, no statistically significant differences can be detected in the Hg removal performance among cold- and hot-side ESPs combined with wet scrubbers.

Response:

EPA concurs with the comment.

Comment:

One commenter (OAR-2002-0056-5564) provided additional information on the ICR fuel sampling to show that the amount of Hg was significantly understated in Gulf Coast lignites because of the test method (ASTM D3684) used in the analyses. When the analytical lab switched to ASTM D 6414, the Hg levels essentially tripled. Method 3684, which most Gulf Coast lignite plants used, is not accurate for lignite with high levels of Hg.

Response:

EPA is aware of the issue but believes that the value is limited in that the final emission limits were based on Hg emissions to the atmosphere rather than on any calculation based on the Hg content of the coal being used. EPA reserves the right to revisit this issue during normal reviews of the NSPS but believes that the revised Hg emission limits adequately address the commenter's concerns.

3.1.7 Cross-Media Impacts

Comment:

Two commenters (OAR-2002-0056-2008, -3478) stated that the implementation of ACI Hg controls could potentially impact the sale of combustion byproducts, eliminating an income stream for utility companies and increasing expenses for permanent ash disposal. One of the commenters (OAR-2002-0056-2008) stated that the largest market segment for coal combustion by-product (e.g, fly ash) use is the construction materials market. Fly ash is used as a replacement for Portland cement in concrete production and other cementitious based applications. The commenter stated that the severe detrimental influence exhibited by activated carbon on air-entrained concrete was shown in a presentation provided at the American Coal Council Mercury and Multi-Emission Compliance: Strategies and Tactics for New and Existing Coal Plants Symposium, Irving, Texas, March 24-25, 2004. The reported findings indicated that the addition of activated carbon in amounts of less than one percent could render fly ash unusable for concrete applications. The laboratory findings are consistent with reports from large-scale demonstration projects such as the one conducted by ADA-ES at WE Energies' Pleasant Prairie Power Plant. In that study, powdered activated carbon was used as the Hg sorbent. Although the activated carbon removed Hg from the flue gas stream during the test program, it also contaminated the fly ash, darkening the light-colored material and making it unusable for air entrained concrete. The commenter stated that the ACI process would not only cause the plant to lose a source of revenue through lost fly ash sales, but lead to additional

disposal cost. The commenter reported that these combined issues were estimated to be valued at $5,000,000 per year (R. Peatier; Mercury removal standards are coming; Where's the technology?, Power, May 2003 p 40).

Response:

EPA agrees that the use of ACI can impact on the usability and disposal of fly ashes from coal-fired utility units. However, we believe that means are available that minimize this impact (e.g., use of a polishing fabric filter following an ESP; the ESP to capture the majority of the "clean" fly ash for re-use and the fabric filter to capture the activated carbon injected between the two units). Further, sorbents are under development and testing that do not cause the same degradation with air-entrained concretes that are posed by activated carbon.

3.2 EMISSIONS LIMITATIONS

3.2.1 General

Comment:

One commenter (OAR-2002-0056-2443) stated that establishing nationwide emission limits is not justifiable given the wide variability in coal properties (e.g., Hg content, Cl content), plant operating practices, and the uncertainty about the chemistry of Hg speciation and its control.

Response:

EPA believes that its use of subcategories in establishing the final emission limits adequately addresses the commenter's concern.

Comment:

One commenter (OAR-2002-0056-2422) stated that the EPA's proposed new source standards are not based on the "best controlled similar source" using a worst-case operating scenario. New coal-fired units are not uniform in design; coal properties and other factors can significantly affect plant designs. Current bituminous PC plant designs typically incorporate a wet scrubber for SO_2 control, an ESP or fabric filter for particulate control, and an SCR for NO_x reduction. New plants designed for PRB coal will likely be dry scrubbed, have a fabric filter, and some advanced form of NO_x control such as SCR. As noted previously, dry scrubbed plants with fabric filters obtain virtually no Hg reduction. An SCR or other form of NO_x control may aid in the reduction of Hg, but there are no data in EPA's ICR database on which to base a sound decision on the effectiveness of NO_x controls in reducing Hg emissions from either eastern or western coals.

Response:

EPA concurs with the commenter's concerns but believes that because the final emission limits were based on the performance or permitted levels of current controls within each subcategory, the commenter's concerns have been addressed adequately.

Comment:

One commenter (OAR-2002-0056-2843) recommended that no standard be promulgated unless existing control technology can be demonstrated to be able to attain and sustain the standard over a wide range of coals and for a long period of time. The commenter stated that this is true whether the emission reduction is to be accomplished by a requirement under either CAA section 111 or section 112. The commenter believes that unless achievable control technology is available at the outset, the construction of new coal-fired facilities will be improbable. Further, the commenter believes that no demonstrated technology exists that is capable of affecting the levels of emissions reduction which would be required under either of EPA's proposed rulemaking. Therefore imposition of either proposed approach would make it extremely difficult, if not impossible, to construct new coal-fired plants. The commenter specifically cites that the latest DOE solicitation for a full-scale demonstration of Hg reduction technologies on a scrubbed unit burning PRB coal will not be concluded until 2005. The first such tests being conducted at the commenter's Holcomb 1 unit will not be concluded until late summer 2004.

Response:

As noted above, EPA concurs with the commenter's concerns but believes that because the final emission limits were based on the performance or permitted levels of current controls within each subcategory, the commenter's concerns have been addressed adequately. Further, as noted later in this document, EPA has reanalyzed the data and revised the NSPS emission limit for new sources.

Comment:

One commenter (OAR-2002-0056-2916) stated that CAA section 111(a)(1) requires that the level of emissions reductions for a new source must reflect a level of performance of a technology that has been put to practice in a number of commercial applications using a number of coal ranks in order to meet the test of being "adequately demonstrated." The commenter stated that there are currently no commercially available technologies that are designed to control Hg from coal-fired power plants to the levels proposed. The EPA must reconsider and revise the proposed NSPS limits in light of the wide range of uncertainty concerning the performance and future availability of commercial Hg control technology. In order to support the emissions levels and time frames set forth in the proposed rulemaking, the commenter believes that the EPA and DOE must make certain that sufficient funds are provided to complete the required R&D to fully develop and commercially demonstrate advanced Hg control technologies. The commenter stated that Hg emission reductions that are required before the

technology has been fully developed will lead to significantly increased costs, to likely fuel switching from coal to natural gas, and to possible disruption of the nation's electricity supply.

Response:

EPA might argue the commenter's discussion of what section 111(a)(1) requires but agrees with the commenter that Hg-specific control technologies are not yet commercially available. Further, as noted later in this document, EPA has reanalyzed the data and revised the NSPS emission limit for new sources.

Comment:

One commenter (OAR-2002-0056-2331) stated that to reduce the possibility of overly stringent source limits and resultant fuel switching, the EPA should set the new source standards on demonstrated, commercially viable technologies as provided in CAA section 111(a). The EPA's proposal to set standards based on "emerging" pollution control technology introduces unnecessary uncertainty in the viability of all fuel sources for future generation of electricity.

Response:

As noted later in this document, EPA has reanalyzed the data and revised the NSPS emission limit for new sources. We do not believe that the final emission limits have been based on "emerging" technology but, rather, that the format of the standards selected will allow for the full development of such technologies.

Comment:

One commenter (OAR-2002-0056-1852) stated that utilities should be allowed the greatest flexibility in switching and blending fuels to meet an emissions standard. Therefore, it is important that the final rule be designed to allow for inclusion of pre-combustion controls as a viable compliance strategy. For many electric generating facilities, pre-combustion Hg removal can be more cost-effective than post-combustion removal, as pre-combustion methods control the Hg while it is in a more concentrated and contained form, permitting significant savings in waste disposal volumes and costs. For older facilities in particular, for which retrofits would be extremely costly, using fuel that has been cleaned and upgraded on a pre-combustion basis offers the most cost-effective compliance method.

One commenter (OAR-2002-0056-1760) stated the final rule should incorporate pollution prevention strategies to remove Hg prior to release to the air.

Response:

EPA believes that pre-combustion removal of Hg is a viable option available to the industry under the final rules.

Comment:

One commenter (OAR-2002-0056-2331) stated that EPA must ensure that any new source emission limits are economically attainable for electric utilities and will not lead to facilities switching to natural gas for base load electrical generation.

Some commenters (OAR-2002-0056-1692, -1768) stated that Hg standards must be technically achievable for all types of coal-based electric generation sources.

Response:

EPA believes that its final rule is founded on the cost requirements of section 111, is technically achievable for all types of coal-based electric generation sources, and will not lead to fuel switching. Note, however, that utilities are free to comply with the final emission limits in any manner they choose.

Comment:

One commenter (OAR-2002-0056-2843) stated that circulating fluidized bed technology sources behave quite differently than pulverized coal sources and should not be used to determine either emission limit levels or allowance allocations.

Response:

As noted earlier, with the exception of coal refuse-fired units (which is a result of the coal rank rather than of the boiler type), the data did not suggest that FBC units (including CFB units) emitted Hg any differently than other boiler types and, therefore, no subcategory specifically for FBC units was established.

3.2.2 Regulated Pollutants

Comment:

One commenter (OAR-2002-0056-2219) stated that the proposed rules fail to address speciation of Hg. Mercury takes different forms (ionic, elemental, particulate) depending on the rank of coal burned. Although ionic and particulate Hg can be controlled by existing technology, additional controls are needed for elemental Hg. This is particularly important in the case of a cap-and-trade program.

One commenter (OAR-2002-0056-2067) stated that there is a lack of effective removal technology for elemental Hg, which is prevalent in Wyoming PRB coal. Without existing technology, it is unfair to the purported neutral treatment of coal ranks to require removal of elemental Hg (which is more prevalent in subbituminous coal) before 2010. This is especially true for those power plant units that have existing scrubbers in place.

Response:

The rank of coal burned impacts the relative amounts of each of the three primary species of Hg emitted; all coals emit some of each species. The final rule is based on the performance and permitted levels of existing technologies for new sources. For existing sources, adequate time is provided before the Phase II cap is in place to allow for the development of the promising Hg-specific control technologies that will effectively capture the elemental Hg.

3.2.3 Format of Standards

3.2.3.1 General

Comment:

One commenter (OAR-2002-0056-3449) objected to the format of the proposed standard because the EPA failed to select a format that best addresses variability. It is wrong for a contaminant where variability of the concentration of the contaminant in a fuel is an important consideration. The appropriate format was used in the MWC standards and the NSPS for SO_2 emissions from coal-fired plants. Both of these rules have a combination standard (X micrograms per cubic meter or W percent control for the MWC units) and Y lb/Btu or Z percent control for the NSPS. This format allows the concentration limit to be based on the average level of the constituent because the percent reduction limit can be used for situations with the constituent level is much higher. The logical way to structure a combination standard is to base the lb/TBtu (or lb/MWh) on the median case and to base the percent reduction on the worst coal case. This ensures that real reductions occur for the median coal and the worst case coal can still be burned with good control.

One commenter (OAR-2002-0056-3406) stated that because of variations in plant design and the coal ranks used, the commenter recommended that the standard for all plants be a combination of a reduction in emission rate or an emission rate, whichever is less restrictive (e.g., X percent reduction or Y lb/TBtu). The commenter stated that this is consistent with the approach used in Connecticut and proposed in other States.

Response:

EPA disagrees that a percent reduction format, or a combination format that includes percent reduction, is appropriate for this rulemaking because of the difficulty in determining where the percent reduction should be assessed. Further, EPA has proposed to eliminate the percent reduction portion of the subpart Da emission limits for SO_2 emissions from coal-fired power plants.

3.2.3.2 Percent Reduction Format

Comment:

Many commenters (OAR-2002-0056-2054, -2067, -2068, -2160, -2224, -2422, -2634, -2661, -2827, -2867, -2922, -3200, -3403, -3514, -3432, -3565, -4891) recommended that the EPA add a "percent reduction" alternative for emission limit standards, based on the Hg in the coal supplied to the boiler and the Hg in the stack. Affected units would have the option of meeting an emissions rate limit or a removal efficiency requirement. Reasons for adopting a percent reduction format include such an approach is appropriate given the variability between and among units and the differences in coal characteristics among coal within a given rank. This would allow units to burn higher Hg content coals by removing Hg to the greatest extent possible. In addition to providing a realistic option for units that would result in significant Hg reductions, this approach ensures that existing coal reserves remain a viable fuel source. Such an option would insure that one coal is not favored over another.

One commenter (OAR-2002-0056-2160) recommended that standards should have an alternative standard to emission limits based on a percent reduction from the raw coal as mined. This alternative would provide some relief for coals with unusually high Hg content while still achieving meaningful emission reduction.

According to Commenter OAR-2002-0056-5535, industry's suggested alternative percent-reduction format is inappropriate because unit operators can control pollutant input levels. In the MACT standards for the brick and structural clay products and clay ceramics manufacturing industries, EPA allowed units to meet either an emissions rate or a percent reduction standard for hydrogen fluoride (HF) and hydrogen chloride (HCl), but did not provide the alternative approach for PM (a surrogate for HAP metals). EPA's reasons for declining to provide an alternative, percent-reduction standard for PM are equally applicable here: EPA decided not to finalize a percent reduction alternative because "a percent reduction standard rewards those facilities that have high inlet PM loadings...[a situation different] from the percent reduction standards for HF and HCl because facilities do not typically have options for reducing the uncontrolled levels of HF and HCl." In other words, a percent reduction alternative is appropriate when the input levels of the HAP in question are outside the control of the operator. When, as here, there are options available to reduce input levels of the HAP being regulated, however, a percent reduction standard has the perverse effect of rewarding those operators who do not take prophylactic steps to reduce input levels. For the coal-fired electric generating industry, as we demonstrated in our initial comments, there are a variety of pre-combustion techniques–such as coal washing–that reduce input levels of Hg and other HAP from all coal types. Allowing an alternative percent reduction approach would reward operators who do not use such techniques and approaches.

Response:

EPA continues to believe that a percent reduction format is not appropriate for this rulemaking. As noted in the proposal preamble, in order to accommodate pre-combustion Hg

control technologies, a percent reduction format would require tracking the Hg concentrations in the coal basically from the mine to the stack, and not just before and after the control device(s) and could be difficult to implement. We believe that this would require an inordinate, and possibly unworkable, recordkeeping effort. We believe that the subcategorization approach and revised emission limits being finalized will address the commenter's concerns.

Comment:

One commenter (OAR-2002-0056-2243) stated that the Hg limits should be set as a minimum percent removal in place of a specific emission limit. This is consistent with EPA's earlier efforts at SO_2 control.

Response:

As noted earlier, EPA has proposed to eliminate the percent reduction portion of the subpart Da emission limits for SO_2 emissions from coal-fired power plants and does not believe that a percent reduction format is appropriate for this rulemaking.

Comment:

One commenter (OAR-2002-0056-3288) supported an emission rate limit rather than a percent reduction requirement. A percent reduction format will likely result in higher overall emissions which would end up being more costly for consumers and would create a bias against cost effective, environmentally-preferable subbituminous coal. An emissions limit will result in the highest level of overall reduction at a lower cost to consumers, avoid massive disruptions to the coal industry, and encourage continued development of effective pre-combustion technologies.

Response:

EPA concurs that an emission rate limit is more appropriate than an emission reduction requirement.

3.2.3.3 Output-based Format

Comment:

One commenter (OAR-2002-0056-3435) recommended that the EPA establish input-based standards for Hg control. Although the output format promotes energy efficiency, this is not the purpose of a standard for protection of public health and the environment. The EPA makes an economic argument for an output-based format (69 FR 4699) which contradicts the purpose of promoting efficiency through emission standards. The output-based limit uses an assumed efficiency and will be based on output energy. Using output energy (gross or net) can introduce error in representing actual emissions because of the variability in assuming efficiency and the introduction of other variabilities inherent to the standard, especially compared to heat

input determinations. Mercury is present in the gas in such trace amounts that the most stringent measurement standard of the emission rate should be used. A lb/TBtu standard has less error than a lb/MWh standard and will better represent emission levels. Because heat input is already required for the Acid Rain Program, this format is already standard and places no additional burden on the plants.

Response:

EPA believes that an output-based standard is consistent with the intent of section 111 and will serve to protect the public health and the environment, as well as promote energy efficiency. Further, EPA has revised, or is in the process of revising, subpart Da to place the emission limits for PM, NO_x, and SO_2 in an output-based format.

Comment:

One commenter (OAR-2002-0056-2161) recommended that the EPA provide the maximum encouragement for energy efficiency by promulgating a standard based upon lb/MWh-net instead of lb/MWh-gross. The true efficiency of a coal-fired unit is based upon how much of its energy is available after reduction by internal station power consumption, measured as MWh-net. Therefore, if EPA's goal is to help encourage increased energy efficiency with the Hg standard, the most effective way to do this is to utilize the net production.

One commenter (OAR-2002-0056-3449) recommended changing the proposed format for the output based standards from lb/MWh "gross" to lb/MWh "net" to encourage efficiency. A net standard, like the one in their State, should lead to lower emissions from electricity productions.

Response:

EPA agrees with the commenters that using the "net" output would more adequately address energy losses within the utility station. However, our intent is to encourage existing units to utilize the output-based format also. Therefore, we believe that the lb/MWh-gross format is more appropriate for this rulemaking because implementation on existing units could require significant and costly additional monitoring and reporting systems because the energy output that is used for internal components (and not sent to the grid) cannot be accounted for by simply installing another meter. EPA agrees that new units could accommodate the lb/MWh-net format but we do not want to institute a dual set of formats for the same industry and the implementation and compliance problems that would result.

Comment:

Two commenters (OAR-2002-0056-3406, -5445) supported the use of an output-based standard because this approach rewards efficiency and allows the market to make decisions about fuel choices rather than favoring one type of generation over another. The commenters also supported the proposed use of gross, as opposed to net, plant energy output. Commenter

OAR-2002-0056-3406 stated that gross energy output is the amount of energy generated before internal energy consumption and losses are considered. Net electricity generation is the amount of energy that is delivered to the energy grid after taking into account internal consumption losses. The commenter notes that those losses can be significant, and can actually increase with the operation of emission controls such as SCR and scrubber units. The commenter concluded that the use of net plant energy output would penalize a power plant that installed additional control equipment, which the commenter takes to be contrary to the intent of the rule.

One commenter (OAR-2002-0056-1969) stated that EPA has suggested that the output-based standard be calculated on gross rather than net energy output basis. According to the commenter, a net energy output based standard is certainly the most comprehensive and is able to capture energy efficiency improvements for the entire plant. The commenter states, however, that EPA is correct in concluding that calculation of emissions on a net energy output basis is a more complex task. The commenter asserts that although that concern may not be the sole reason to exclude a net energy output standard, a gross energy based standard is able to capture most efficiency improvement projects and is less burdensome to administer. The commenter supports an output-based standard based on a gross energy output basis.

Response:

EPA concurs with the commenters. However, we note that a practice of overall energy efficiency would also look to utilizing more efficient equipment on the SCR and scrubber units, although we do not believe that use of lb/MWh-net is appropriate here.

Comment:

Two commenters (OAR-2002-0056-1969, -2850) supported the option of either an input-based or a gross output-based standard for existing units as long as the mathematical relationship between the two standards is equitable. The output-based standard offers a regulatory incentive to improve unit efficiency. Any output-based standard should give consideration to average unit efficiency subcategorized for unit type so that differences in installed design can be reflected when establishing Hg control stringency. An output-based standard should not be periodically revised for existing units because doing so would discourage energy efficiency as a compliance option for existing sources.

Response:

EPA believes that the conversions used in developing the final emission limits are equitable and appropriate. However, EPA does not believe that it is appropriate to average unit efficiency subcategory-by-subcategory at this time.

Comment:

One commenter (OAR-2002-0056-4132) objected to using an output-based emission limit format for old or new sources. Output-based emission standards are not desirable. First,

they draw in complexities like gross electrical output, net electrical output, and disassociated monitoring systems. Secondly, they deal poorly with systems that choose to use steam for a variety of auxiliary functions, because they may have a corresponding loss of electrical output. Thirdly, for facilities involved with some level of cogeneration, complex and unnecessary accounting regimes are required. Input-based emission standards work well, and should be available to all emission units.

Response:

EPA disagrees with the commenter. Although output-based formats do require different considerations than input-based formats, all formats involve a certain amount of complexity. The final rule addresses the issues related to cogeneration units in a manner similar to that done under subpart Da for NO_x emissions from such units. EPA continues to believe that output-based emission limits encourage energy efficiency, are consistent with other Agency actions on subpart Da, and are appropriate for this rulemaking.

Comment:

One commenter (OAR-2002-0056-3210) disagreed with the method EPA used to convent input-based limits to output-based limits. The commenters stated that the EPA should establish output emission limits for Hg using actual emission data, not a calculated value from a heat input-based standard.

Response:

The conversion used by EPA was based on that used in the subpart Da NO_x revisions, which were based on data received from new facilities.

Comment:

Several commenters (OAR-2002-0056-3210, -1474, -2721, -3437, 3459) disagreed with the power plant efficiency values EPA used to convent input-based limits to output-based limits. The commenters stated that the plant percent efficiencies used by the EPA are too low.

One commenter (OAR-2002-0056-3437) used the 1999 National Electric Data System to estimate the efficiency of the 69 coal-fired units greater than 25 MW that are potentially affected by the proposed rule. The average efficiency is 34 percent for existing units. The commenter provided data showing that new units can achieve efficiencies significantly greater than 35 percent with IGCC units operating at 42 to 47 percent efficiency and certain pulverized units achieving 40 percent efficiency.

Several commenters opposed the use of 35 percent efficiency as the baseline efficiency for new units. One commenter (OAR-2002-0056-1474) stated that the baseline efficiency should be set at 35 percent to move power plants toward higher efficiencies. Commenter OAR-2002-0056-2721 disagreed that 35 percent efficiency is an appropriate baseline for all new units. The

commenter stated this may be a good assumption for higher quality fuels but not for the low rank fuels. According to Commenter OAR-2002-0056-3459, EPA used a 35 percent baseline efficiency for new units and did not provide any support for their assumption. The commenter stated that the EIA assumes that a new scrubbed coal plant with SCR will have an efficiency of 38 to 40 percent. For new IGCC units, the EIA assumes 42.5 percent efficiency.

Response:

EPA is unclear about the reference to "69 coal-fired units...that are potentially affected by the proposed rule." Only new units would be impacted under the section 111 approach. EPA used data from the EIA (OAR-2002-0056-0017) that provided average coal-fired power plant efficiencies over the period 1935 to 1996 for all boilers and fuels. The 35 percent value chosen is higher than that achieved in all but 2 of those years.

3.2.4 Numerical Emission Limits

3.2.4.1 General

Comment:

Several commenters (OAR-2002-0056-2843, -2897, -2911, -3324) stated concerns that the proposed emission limits for new sources are unjustifiably stringent citing general reasons including the control technologies needed to comply with the standards have not been adequately demonstrated, the controls are too costly to implement, and the standards would prevent the use of much of the coal resources in the U.S.

Many commenters (OAR-2002-0056-1692, -1804, -2068, -2224, -2243, -2264, -2365, -2431, -2661, -2835, -2891, -2898, -2907, -2948, -3200, -3403, -3432, -3514, -3517, -3560) stated concerns that the proposed emission limits would adversely impact the construction of new coal-fired power plants in the U.S. Reasons cited by the commenters include the following. The proposed Hg emission standards are at levels that are not be achievable with currently available technology except for the lowest Hg content coals. This would preclude the ability of new units to combust coal from many seams that have high Hg content levels. The proposed limits fail to account for variability in the Hg content from coals mined from a given seam. Also, no vendors of control technology are willing to guarantee Hg removal at the rates needed to achieve the proposed emission levels. No company would make a large capital investment in a new plant if performance guarantees to meet required environmental standards were not available. Financial institutions will be very wary of participating in projects that are given emission limits that cannot be guaranteed by equipment suppliers and whose limits will be difficult to verify. Additionally, if facilities are forced to use alternative coal sources, it could dramatically increase the cost of the fuel and decrease the economic viability of the units, also impacting the decision to construct the unit.

Several commenters (OAR-2002-0056-1952, -2331, -2560, -2725, -2833, -2897, -3200, -3257) stated concerns that the proposed emission limits would require base load electric utility

generating units to switch to firing natural gas to ensure compliance with the standards. Commenters stated that forced fuel switching from coal is unacceptable as a national energy policy. It would adversely impact natural gas supplies and costs to other natural gas users. It is important that EPA set emission rates that maintain coal as a major fuel source option in a diversified national energy program.

One commenter (OAR-2002-0056-2210) stated that the EPA's proposed limits for new sources, under either a MACT or cap-and-trade (NSPS) approach, are unduly stringent and would preclude the use of many U.S. coals–bituminous, subbituminous and lignite. Unrealistic new source limits could present an insurmountable barrier to the construction of new, low-cost coal powered generation, conflicting with the Administration's energy policies favoring the development of all forms of domestic energy. The proposed emission limits for new plants need to reflect the emission performance that can be expected from different coal ranks at plants equipped with state-of-the-art emission controls, and must ensure that all U.S. coals may be utilized at such new plants. The U.S. can ill afford to create artificial barriers to the development and use of its largest domestic, fossil energy resource.

One commenter (OAR-2002-0056-2160) stated that any revised rules should be fuel neutral (equitable for all geographic regions and coal ranks), reduction requirements should be based on reasonable estimates of when technology will be available to meet the limits (and consider economic and time constraints), and take into account the effect of the inherent variability of coals with respect to Hg content, combustion characteristics, and control system performance.

Several commenters (OAR-2002-0056-1175, -1658, -1781, -1783, -1848, -1861, -1863, -2333, -2924) stated that the EPA's proposed limits are more stringent than those recommended by industry as part of the workgroup recommendations. The proposed limits do not reflect the level of control that is technically achievable.

Response:

As stated in the preamble, EPA has re-analyzed the data collected in the 1999 ICR and examined the Hg limits issued in recently issued permits to establish new source NSPS Hg emissions limits for five subcategories of Utility Units. Based on these findings, EPA believes that the revised new-source NSPS Hg emission limits are reflective of the level of Hg control that is currently technically achievable for these subcategories.

Comment:

Several commenters (OAR-2002-0056-2871, -2889) stated that the proposed limits are flawed because EPA failed to consider all available technologies. Activated carbon injection is commercially available and widely recognized as a viable control for Hg. It has been demonstrated with pilot and full-scale demonstration projects on coal and has been used for over 10 years on other large combustion projects. States are now requiring it on new coal-fired units for Hg control. EPA's failure to consider this technology is inconsistent with its past approaches

for developing Hg limit for combustion sources and EPA provides no justification for the change.

One commenter (OAR-2002-0056-2108) stated there is not adequate justification for not examining more control technologies/options in setting the emission limits for new sources.

Response:

EPA disagrees with the commenters. As noted earlier, EPA does not believe that ACI, or any other Hg-specific control technology, has been adequately demonstrated under the criteria of section 111 to be considered viable control options for new sources under this rulemaking. However, we do believe that the cap-and-trade approach being taken will allow such technologies the necessary time to be fully proven for widespread commercial installation.

Comment:

One commenter (OAR-2002-0056-2422) stated that the EPA's proposed limits for new sources must be revised to fully account for variability in the performance of the "best performing" unit, regardless of whether it imposes an emissions limit or a "cap-and-trade" program. Also, the proposed emission limits for new plants need to reflect the emission performance that can be expected from different coal ranks at plants equipped with state-of-the-art emission controls, and must ensure that all U.S. coals may be utilized at such new plants. The U.S. can ill afford to create artificial barriers to the development and use of its largest domestic energy resource.

Response:

Although use of the "best performing unit" is not applicable under CAA section 111, EPA believes that the reanalysis noted earlier adequately addresses the concerns related to variability, use of different coal ranks, and emission controls noted by the commenters.

Comment:

One commenter (OAR-2002-0056- 2441) stated that the EPA ignored their workgroup position on limits for existing and new sources that would allow the use of all coals. The proposed limits for western subbituminous and lignite coal are substantially less stringent that the limits recommended by the industry workgroup participants, the proposed limit for eastern bituminous coal is 9 percent more stringent. More than half of eastern bituminous coal would require greater than 75 percent removal to meet the limit (beyond EPA's estimate of 50 to 70 percent) removal capability for current technologies). In contrast, the proposed limit for western subbituminous coal gives PRB coal a free ride in that most of 62 percent of these coals could meet the limit without any controls. This would encourage cherry picking of western coal that could be sold without the need to reduce emissions. This preferential treatment would invite massive fuel switching to western coal and, thus, a massive shift of coal production from eastern to western states. This would have a disastrous economic impact on coal mining. For existing

sources, 84 to 100 percent of the bituminous coal mined in eastern states could not be used under the NSPS limits, even at 80 percent removal.

Response:

EPA believes that the emission limits developed through the reanalysis of the data will address the concerns noted by the commenter and provide equitable treatment for all coal ranks.

Comment:

One commenter (OAR-2002-0056-2068) stated that the EPA should set a separate emission limit for fluidized-bed combustors.

Response:

As noted earlier in this document, EPA does not believe that the data justify a separate subcategory for FBC units and, thus, no separate emission limit has been established for FBC units utilized in the bituminous, subbituminous, and lignite subcategories.

Comment:

One commenter (OAR-2002-0056-2913) stated that the proposed limits based on the use of wet limestone scrubbers for Hg control do not include an allowance for the Hg content of the limestone used as the sorbent material.

Response:

Because the emission limits established are based on Hg testing conducted at the stack (i.e., following any limestone injection into the wet- or dry-scrubber), EPA believes that any Hg contained in the limestone has been accounted for in the revised emission limits.

Comment:

One commenter (OAR-2002-0056-2108) stated that new units should be required to reduce Hg emissions by 90 percent regardless of fuel type.

One commenter (OAR-2002-0056-3449) recommended that emissions limits for all new units (regardless of the rank of coal) be determined on a case-by-case basis and be no higher than the proposed limit for new bituminous coal units, along with a 90 percent control option to address high Hg coals.

Response:

As noted earlier, EPA does not believe that a percent reduction format, or combination format including percent reduction, is appropriate for this rulemaking. Further, EPA believes

that it is consistent with the criteria of CAA section 111 to establish the emission limits for each subcategory based on information available for each subcategory which is the procedure followed for this rulemaking. Nor does EPA believe that CAA section 111 allows for a case-by-case determination of new-source NSPS emission limits as suggested by the commenter.

Comment:

Commenter OAR-2002-0056-2922 stated that it is not clear why such a strange mix of units is required throughout the proposed rules. The commenter found lb/TBtu, 10^{-6} lb/MWh, ounces, tons, MMBtu, etc. For example, it does not make sense for the State allocations to be done in factional tons while the unit allocations are in ounces. Why not use ounces for both?

Response:

EPA agrees with the commenter and has standardized the units of measure as much as possible in the final rules.

3.2.4.2 Approach to Setting New-source Limits

Comment:

Two commenters (OAR-2002-0056-2422, -2862) stated that the EPA proposed the same numerical limits for new source MACT under CAA section 112 and the alternative NSPS under CAA section 111. Under section 112, the new source MACT limit should "not be less stringent than the emission control that is achieved in practice by the best controlled similar source." Under section 111, NSPS should "reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements)." Limits under both sections of the CAA begin with an assessment of what limit is achievable in practice with the best available controls, but the NSPS goes on to consider cost, energy use and non-air impacts. Accordingly, it is inappropriate and inconsistent with the CAA for the EPA to establish an NSPS requirement based on an analysis undertaken pursuant to the requirements of CAA section 112.

Response:

EPA agrees with the commenters who indicated that the new-source NSPS limits were not established in a manner consistent with the requirements of CAA section 111. We have, therefore, re-analyzed the information collection request (ICR) data collected in 1999, and examined the Hg limits in recently issued permits. Based on this refined analysis, we have arrived at the following new-source NSPS Hg emission limits for the five subcategories:

Bituminous units: *0.0026 ng/J (21 x 10^{-6} lb/MWh);*
Subbituminous units:
- wet FGD units *0.0055 ng/J (42 x 10^{-6} lb/MWh);*

- dry FGD units: *0.0103 ng/J (78 x 10^{-6} lb/MWh);*
Lignite units: *0.0183 ng/J (145 x 10^{-6} lb/MWh);*
Coal refuse units: *0.00017 ng/J (1.4 x 10^{-6} lb/MWh);*
IGCC units: *0.0025 ng/J (20 x 10^{-6} lb/MWh).*

Documentation for this re-analysis may be found in the e-docket (OAR-2002-0056).

To establish the revised new-source limits, EPA re-examined the 1999 ICR data which includes an estimate of the Hg removal efficiency for the suite of emission controls in use on each unit tested. The EPA focused primarily on the 1999 ICR data because it is the only test data for a large number of Utility Units employing a variety of control technologies currently available to the Agency and because there is very limited permit data for new or projected facilities from which to determine existing Hg emission limits. (The EPA has historically relied on permit data in establishing new-source NSPS limits because it believes that such limits reasonably reflect the actual performance of the unit.) We analyzed the performance of currently installed control technologies in the respective subcategories in an effort to identify a best adequately demonstrated system of emission reduction, also referred to as a best demonstrated control technology (BDT), for each subcategory. To do this, we determined the combination of control technologies that a new unit would install under the current NSPS to comply with the emissions standards for PM, SO_2, and NO_x. Based on the available data, units using these combinations of controls had the highest reported control efficiency for Hg emissions. Thus, we determined that BDT for each subcategory of units is a combination of controls that would generally be installed to control PM and SO_2 under the NSPS. For bituminous units, BDT is a combination of a fabric filter and a FGD (wet or dry) system. For subbituminous units, BDT was determined to be dependent on water availability. For subbituminous units located in the western U.S. that may face potential water restriction and, thus, do not have the option of using a wet FGD system for SO_2 control, BDT is a combination of either a fabric filter with a spray dryer absorber (SDA) system or an ESP with a SDA system. For subbituminous units that do not face such potential water restrictions, BDT is a fabric filter in combination with a wet FGD system. For lignite units, BDT is either a fabric filter and SDA system or an ESP with a wet FGD system.

To determine the appropriate achievable Hg emission level for each coal type, a statistical analysis was conducted. Specifically, the Hg emissions limitation achievable for each coal type was determined based on the highest reported annual average Hg fuel content for the coal rank being controlled by the statistically-calculated control efficiency for the BDT determined for that fuel type. The control efficiency for BDT was calculated by determining the 90^{th} percentile confidence level using the one-sided z-statistics test (i.e., the Hg removal efficiency, using BDT, estimated to be achieved 90 percent of the time). The data used consisted of stack emission measurements (pounds Hg per trillion Btu, lb Hg/TBtu) for each unit, the average fuel Hg content for the fuel being burned by that unit during the test (parts per million, ppm), and the highest average annual fuel Hg content reported for any unit in the coal rank. Because the Hg emissions from any control system is a linear function of the inlet Hg (i.e., Hg fuel content), assuming a constant control efficiency, the reported highest annual average inlet Hg was adjusted to determine the potential maximum Hg emissions that would be emitted if BDT was employed. The calculated 90^{th} percentile confidence limit control reduction for each

subcategory, based on the calculated highest annual average uncontrolled Hg emissions, in lb Hg/TBtu, for the subcategory was determined to be the new source emission limit. Finally, the new source limit for IGCC units and its justification remains unchanged from the limit proposed in January 2004 (69 FR 4652).

EPA also evaluated recent, available permit Hg levels for comparison with the limits presented above. EPA does not believe that the use of permit Hg limits is appropriate for independently establishing new-source NSPS emission limits because of the limited number of permits issued with Hg emission levels and the limited experience of both State permitting authorities and the industry itself with establishing appropriate permit conditions. However, comparison of the available permit limits with those developed by EPA is a valid "reality check" on the appropriateness of EPA's limits. Available permits on bituminous-fired units have Hg emission limits ranging from approximately 20 x 10^{-6} lb/MWh to 39 x 10^{-6} lb/MWh; those for subbituminous-fired units range from 11 x 10^{-6} lb/MWh to 126 x 10^{-6} lb/MWh. Considering the limited number of permits and the limited experience in developing appropriate Hg limits for those permits, EPA believes that its final new-source NSPS Hg emission limits 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.

Further, EPA concurs with those commenters who indicated that we had overstated the variability in the context of the proposed CAA section 111 NSPS limits by using both a rigorous statistical analysis and a 12-month rolling average for compliance. Therefore, for the final rule, while we have retained the 12-month rolling average for compliance, we have used the annual average fuel Hg content in the ICR data to establish the NSPS limits. Given the favorable comparison with the available permit data, we believe that variability has been adequately addressed. Documentation for the new-source limits is provided in "Statistical Analysis of Mercury Test Data to Determine BDT for Mercury" (OAR-2002-0056-6192).

3.2.4.3 Bituminous Coal-fired Units

Comment:

Two commenters (OAR-2002-0056-2160, -3199) stated that in the supplemental notice, the EPA stated that 50 to 70 percent Hg removal technologies may be commercially available after 2010 which could address emissions from bituminous coal. The proposed emission limits would require about 94 percent reduction from the average bituminous coal. This is higher than EPA's assessment of the Hg-specific control technologies which would be available at the time of implementation. The standards should be based on the emission reduction that is achievable at the time of implementation. Reductions should be based on realistic estimates of when technology will be available and include consideration of the economic and time constraints in meeting the limits.

One commenter (OAR-2002-0056-3445) stated that the control level required of new sources under either of EPA's proposed regulatory approaches would make it nearly impossible to build new bituminous coal-fired power plants.

One commenter (OAR-2002-0056-2862) stated EPA's proposed emission limit for new bituminous units contradicts the Agency's findings about achievable Hg reductions and would prevent the use of many coals. If the Hg emission standard for new bituminous coal units is set at the proposed 0.6 lb/TBtu emission rate, coals from many regions of the country could not be used in new coal-fired plants because Hg removal in excess of 90 percent would be required. This would eliminate billions of tons of coal from the nation's energy supply. The commenter included an analysis that the commenter stated demonstrated that the majority of bituminous coal supplies available to utilities in the Midwest would be unable to achieve the proposed emission standard. The bituminous coals used in the analysis represent typical coals (coals from West Virginia, Pennsylvania, Kentucky, Illinois and Colorado) that a new unit in the Midwest would burn.

Response:

As noted above, EPA has reanalyzed the data and revised the new-source NSPS Hg emission limits which should address the commenter's concerns.

Comment:

One commenter (OAR-2002-0056-2064) stated that the proposed limits for bituminous coal are above the levels that are technically achievable and cost effective. For bituminous coal, proposed limit would require a 77 percent reduction but this is well below the average 90 percent control demonstrated by fabric filters. This State recently permitted a plant for 90 percent removal for bituminous coal using a fabric filter and wet FGD. These controls are applicable to existing and new units.

Response:

As noted elsewhere, EPA has reanalyzed the data and revised the new-source NSPS Hg emission limits based on the use of current technologies.

3.2.4.4 Subbituminous Coal-fired Units

Comment:

One commenter (OAR-2002-0056-2535) stated that the Wyoming PRB subbituminous coal, which is the most widely used subbituminous coal, should not be used to establish Hg emission limits for all subbituminous coal-fired plants. Instead, Colorado, Montana, and New Mexico subbituminous coals should be used. These coals are typically higher in caloric (Btu) content, and resemble a bituminous coal. Wyoming PRB coal grades out as a Subbituminous C coal, while most other western subbituminous coals grade out as Subbituminous A (according to ASTM standards). For the proposed limit, an analysis by the National Mining Association estimates that 41 percent of subbituminous coals would not be able to meet the limit with any degree of confidence due to the high variability in Hg content of the coal.

Response:

EPA has used the data and information available, including permit information, to revise the new-source NSPS Hg emission limits for all of the subcategories, including subbituminous. We believe that these revised limits will accurately reflect the level of control expected in each subcategory. EPA does not understand why PRB coal should be excluded from this analysis, particularly given the fact (acknowledged by the commenter) that it is the most widely used subbituminous coal.

Comment:

One commenter (OAR-2002-0056-3437) opposed the proposed emission limit for subbituminous coal. The proposed limit would require little or no control at some power plants in Indiana that use subbituminous coal or a blend of bituminous and subbituminous coal. This disparity also can cause bituminous units to switch to subbituminous coal or a blend of the two, which would increase Hg emissions above 1999 levels.

One commenter (OAR-2002-0056-3449) stated that the proposed limit for subbituminous coal-fired units is three times higher that the proposed limit for bituminous coal. The proposed limit is so high that it would result in little, if any, Hg reductions. The ICR data shows that the proposed limit is about the average Hg content of subbituminous coal, assuming all Hg in the coal is emitted. With co-benefits of existing controls, over 80 percent of subbituminous coal is likely to be burned without any additional control. About two-thirds of the subbituminous coals have Hg content less than 5.8 lb/TBtu (the proposed limit). Assuming a 30 percent co-benefit of minimal existing controls, this results in equivalent Hg content of more than about 8.3 lb/TBtu for which added control would be needed. Only about 15 percent of subbituminous coal is above this level. And, when long term averaging is considered, even fewer subbituminous coal-burning units are likely to required controls. Even if no units switch from bituminous to subbituminous coal, Western states will obtain little or no Hg reduction. If widespread switches to subbituminous coal occur, the East will have much higher Hg emissions than EPA projects.

Response:

EPA has used the data and information available, including permit information, to revise the new-source NSPS Hg emission limits for all of the subcategories, including subbituminous. We believe that these revised limits will accurately reflect the level of control expected in each subcategory.

Comment:

Several commenters (OAR-2002-0056-2064, -2198) stated that the proposed limits for subbituminous coal-fired units are too high. In Wisconsin, only one plant in the State (the largest unit with the highest emission rate) would be required to reduce emissions at all; this plant would need to reduce emissions by 40 percent. Plants firing subbituminous coal should be capable of achieving 50 to 83 percent removal from fuel input based on use of a fabric filter

alone. One State recently permitted one coal-fired plant at 83 percent removal for subbituminous coal (1.70 lb/Btu) using a fabric filter (dry FGD system) with sorbent injection. This control equipment is applicable to existing and new units.

Response:

As noted above, EPA has used the data and information available, including permit information, to revise the new-source NSPS Hg emission limits for all of the subcategories, including subbituminous. We believe that these revised limits will accurately reflect the level of control expected in each subcategory. Further, it has also been noted that EPA does not believe that ACI is a commercially available technology upon which a CAA section 111 standard can be established.

Comment:

One commenter (OAR-2002-0056-2535) stated that the AES Hawaii power plant should not be used to set the subbituminous emission limit for two reasons. First, the plant is an FBC unit, which relies on a fundamentally different combustion process and is not representative of the type of plant that burns subbituminous coal in the 48 contiguous States. Second, the plant burns Indonesian subbituminous coal, which is also not representative of the subbituminous coal burned in the 48 contiguous States. In addition to the coal not being representative, EPA must recognize that coal is our largest reserve of domestic fossil fuel, and should not be using a foreign coal to set a domestic standard. This goes against EPA's stated principle of not considering fuel switching as a viable method for setting a MACT floor. Use of Indonesian coal to set the MACT floor will result in more domestic coal being displaced from use in domestic coal-fired power plants.

Response:

The AES Hawaii facility was one of nine subbituminous-fired units used in establishing the revised new source NSPS emission limits. EPA did not feel that it would be appropriate to exclude this unit from the reanalysis because (1) at least one new subbituminous-fired unit has received a permit based on the use of FBC technology in Utah (and, thus, FBC technology is representative of the type of plant that could burn subbituminous coal in the contiguous 48 States), and (2) Indonesian coal was reported to be used by at least two other utility units in 1999 (and, thus, could be used by other units in the U.S.).

Comment:

One commenter (OAR-2002-0056-3437) requested that EPA examine the recent State MACT/BACT decisions that have required ACI. In particular, Iowa set a case-by-case MACT limit equal to 1.7 lb/TBtu based on ACI with 83 percent control efficiency using PRB coal.

Response:

As noted earlier, EPA does not believe that Hg-specific control technologies, including ACI, are commercially available for nationwide application to the coal-fired utility industry. Installation of such technologies on a limited number of units (e.g., the one cited) is possible and will serve to advance the technologies such that they are widely for use in compliance with the phase II cap.

3.2.4.5 Lignite-fired Units

Comment:

One commenter (OAR-2002-0056-3469) supported the proposed limits. The commenter stated that despite flaws in the ICR data used to determine the emission limits, they supported the emission limits for existing units of 9.2 lb/TBtu for Fort Union lignite-fired units.

Another commenter (OAR-2002-0056-2115) supported the proposed limit for lignite because it is the same level that would be required under the Clear Skies proposal. An unattainable Hg limit would result in a practical ban on lignite as fuel. Texas mines over 40 million tons of lignite coal per year for use as power plant fuel.

Response:

EPA concurs that the standards must be achievable by all coal ranks.

Comment:

One commenter (OAR-2002-0056-3514) stated that currently, no technology has been shown to be effective in capturing Hg from lignite coals. Although EPA has proposed for lignite more reasonable emission limits, it still has not been shown that these levels can be met. Lignite and other low-rank western coals face additional obstacles that do not affect other coals, namely higher ash, lower Cl and higher elemental Hg content. Accordingly, these factors make it impossible, at least currently, to attain the removal percentages being achieved with other coals.

One commenter (OAR-2002-0056-2054) stated that the EPA has not proposed standards for new lignite-fired units on a level of performance that is "achievable" by a unit that is "similar" to most new lignite-fired units. The commenter stated that the highest Hg removal rate of any lignite-fired plant in the ICR data was 21 percent, and the plant that achieved this removal rate, Stanton Station, is a relatively small, older plant that is definitely not "similar" to a new lignite-fired unit. According to the commenter, the agency did not base its new unit standard on performance, but rather on the lowest Hg coal; the result of this basis is to eliminate the vast majority of lignite reserves from any new units. The commenter asserts that the choice of best performing unit should comply with the direction given by the DC Circuit Court in National Lime Association v. EPA, 627_F.2d 416, 431n. 46(1980). The commenter stated that this best performing unit is based, according to the court, on a level of performance that can be achieved

"under the most adverse circumstance which can reasonably be expected to occur." Therefore, the "best controlled" source must be taken into account to predict emissions from any reasonable situation, including different lignites.

Response:

As noted above, EPA has revised the new-source NSPS Hg emission limits based on a reanalysis of the available information, including permits. We believe that the revised emission limits address the commenters' concerns.

Comment:

One commenter (OAR-2002-0056-3478) requested that any emission limits for lignite-fired power plants include Gulf Coast lignite as a separate subcategory. Based upon their evaluation of the tested units, the commenter requested that EPA set any limit for Gulf Coast lignite-fired units at a rate no less than 28 lb/TBtu. The commenter stated that if EPA does not establish a separate subcategory for Gulf Coast lignite with a higher standard, then a percent reduction option and/or a "safety net" must be offered so that units in Texas, Louisiana, and Mississippi can continue to utilize locally mined lignite as fuel.

Two commenters (OAR-2002-0056-2915, -3463) stated that Gulf Coast lignite cannot achieve the reductions required to meet the proposed standard for lignite Because it was set with units firing North Dakota lignite. One commenter (OAR-2002-0056-2915) stated that coal-fired utility units already face emissions control requirements that are duplicative, contradictory, costly, and complex, and create enormous uncertainty for future investment and that adding Hg emissions regulations will create even greater challenges for coal-fired utility units, and this is especially true for Gulf Coast lignite because its unique physical composition makes reductions in Hg emissions from utility units firing it very difficult to achieve and more difficult to achieve than for non-lignite coal-fired utility units.

One commenter (OAR-2002-0056-4891) added that the proposed Hg rule rules should be revised to better recognize the high concentration and type of Hg present in Gulf Coast lignite and the difficulties associated with controlling its Hg emissions as compared to Hg emissions from other coal ranks. The commenter stated that without significant changes to the proposed Hg rule to lessen compliance costs, it is likely that most Gulf Coast lignite mines and some Gulf Coast lignite-fired power plants will ultimately be forced to close. According to the commenter, power grid stability would be compromised without the generation capacity provided by Gulf Coast lignite-fired power plants, resulting in the potential for frequent and sustained power outages that would undermine economic stability and prospects for economic growth.

One commenter (OAR-2002-0056-3478) believed the Hg content in Gulf Coast lignite is higher than the ICR data indicate, a more accurate analytical method for Cl in coal demonstrates that the Cl content in Gulf Coast lignite is much lower. The commenter also believed this revised information on Cl content may explain why lignite combustion results in a significant percentage of elemental Hg being emitted.

One commenter (OAR-2002-0056-2929) expressed concern that facilities burning Texas lignite will be unable to comply with the proposed Hg emission limits because the best performing lignite units all fire cleaner-burning North Dakota lignite.

Response:

As noted elsewhere, EPA does not see a basis at this time for further subcategorizing lignite coals.

Comment:

Several commenters expressed concern over the impacts resulting from the stringent rules for lignite coals. The commenters (OAR-202-0056-1692, -2915, -3510, -3543, -4891) were concerned that stringent rules for lignite coal would result in fuel switching and have negative impacts on lignite-burning units. One commenter (OAR-2002-0056-2915) stated that EPA must ensure that the Hg rule does not disadvantage coal, especially Gulf Coast lignite, because doing so would aggravate the already precarious natural gas supply and price situation. The commenter stated that if the Hg rule was to even slightly decrease the dependence on coal, the natural gas supply and the price problems would increase. According to the commenter, it is estimated that forced replacement of coal with natural gas as fuel in electric generation would increase the demand for natural gas by about 35 percent and would increase natural gas prices by about 33 percent. According to one commenter (OAR-2002-0056-3510), natural gas is not available to utilities in the winter when it is apportioned to residential users. One commenter (OAR-2002-0056-1692) stated that the proposed lignite limit of 9.2 lb/Btu is so stringent that it would preclude many southern lignite coals from future use and would promote the use of natural gas, especially in smaller plants, where the high cost of controls may not be justified given the anticipated life of the plant. According to another commenter (OAR-2002-0056-3543), the current rule structure could cause generators to switch coal ranks, primarily from lignite and subbituminous to bituminous coal with resultant economic impacts. Without a higher limit for Gulf Coast lignite, commenters (OAR-2002-0056-3510, -4891) stated that their State economies will suffer because lignite is an important fuel in their State. One commenter (OAR-2002-0056-2915) stated that utility units designed to burn lignite cannot easily, quickly, or cheaply switch to burn other fuel types. According to the commenter, lignite's low heat content and its other properties would require time consuming and expensive alterations to allow them to burn non-lignite fuels. The commenter further stated that lignite-fired utility units are often parties to long-term contracts to purchase the lignite; therefore, even if such utility units could no longer burn lignite, they would still be required to purchase it pursuant to any such long-term contracts. The commenter also added that Gulf Coast lignite-fired utility units in Texas are located on the property from which the lignite is mined and that for many such units, rail lines that could be used to transport other types of fuel to the site would have to be constructed.

Response:

As noted elsewhere, EPA has reanalyzed the new-source NSPS limits and believes that the emission limit being finalized is achievable and appropriate.

Comment:

Several comments addressed the control of Hg from lignite-fired units. Three commenters (OAR-2002-0056-3327, -3469, -4191) expressed concern regarding the availability of proven control measures. According to one commenter (OAR-2002-0056-3469), the lack of availability on the market of proven cost-effective control and monitoring equipment will make compliance with the proposed regulations difficult for utilities, particularly those burning lignite. The commenter supported proposals which give utilities flexibility in how they implement controls and comply with the regulations and which provide incentives to comply as quickly as practical and make the most cost-effective investments that provide the largest emissions reductions. Thus, the commenter supported EPA's proposal to allow utilities to use facility-wide averaging, system-wide averaging, and use 12-month rolling averages to calculate emissions and demonstrate compliance. One commenter (OAR-2002-0056-3327) was concerned that despite the progress made in their State and efforts to continue identifying new technologies to control emissions from coal-fired power plants, the imposition of the proposed requirements will force the closure of lignite-fired power plants prior to the time that effective emissions control technology can be developed and made commercially available.

One commenter (OAR-2002-0056-3478) cited lignite properties in addition to monitoring technology as the main hindrance to pollution control companies providing a Hg removal guarantee. Citing the high degree of elemental Hg remaining in flue gases of lignite as well as lignite's tendency to have relatively high total Hg content, the commenter believed they have valid concerns that Hg control for lignite-fired boilers will be more difficult and costly than for bituminous coal-fired boilers. According to the commenter, coal analysis from one mine indicated that a 59 - 76 percent reduction in Hg emissions would be required. The commenter also reports that similarly, if they examine the 70 percent lignite/30 percent PRB data, a weighted average limit of 8.18 lbs/TBtu would have to be met. According to the commenter, one pollution control company does have experience with an ACI system supplier that have given guarantees of 50 percent removal for PRB coals at a carbon consumption rate equivalent to an expenditure of ~$5M per year and subject to very specific restrictions and very limited liability, but no such guarantees to date have been given for lignite-fired plants. The commenter further stated that the PRB guarantees to date have been predicated upon availability of necessary quantities of suitable activated carbon, total amount of Hg entering the system, and averaging period allowed to meet guarantees. According to the commenter, Hg control technologies are highly coal and boiler/AQCS configuration dependent, not to mention the issues with test accuracy when measuring Hg with a concentration six orders of magnitude less than SO_2. The commenter stated that it will only be after multiple demonstrations have been completed before all the anomalies are sorted out in order for suppliers to take on the risk of Hg removal guarantees.

Response:

EPA believes that the regulatory approach being taken will address the commenters' concerns, particularly with regard to the flexibility afforded to a company. The flexibility afforded by the cap-and-trade approach will preclude any concerns about having to arbitrarily close coal-fired utility units and provide the time necessary to fully develop the emerging Hg-specific control technologies. Further, EPA believes that reliable, cost-effective Hg monitoring systems are available and will be further refined by the time utilities must be in compliance with the revised standards.

Comment:

One commenter (OAR-2002-0056-3478) stated that regulations to control SO_2 and NO_x will require the installation of pollution controls that will also capture the forms of Hg that tend to deposit nearby. The commenter stated that, based on testing of SCR performance for Hg co-benefits on a lignite facility in North Dakota, SCR will not provide much, if any, Hg co-benefit reduction. According to the commenter, SCR technology is ineffective in oxidizing Hg and that the saltation of calcium and sodium ash deposits fouls the catalyst rendering the SCR technology ineffective for NO_x control.

Response:

EPA believes that the cap-and-trade approach being taken will address the commenter's concerns. For the new-source NSPS Hg emission limits, EPA has not assumed any removal contribution by SCR units on lignite coal.

Comment:

One commenter (OAR-2002-0056-4891) stated that, given the lack of scientific evidence linking health impacts to Gulf Coast lignite-fired power plant Hg emissions and its insignificant contribution to Hg emissions relative to other sources and the global Hg emissions pool, there is no present justification for a regulation with as significant an economic impact as the proposed Hg rule.

Response:

EPA sees no basis for excluding Gulf Coast lignite from the revised standards.

Comment:

One commenter (OAR-2002-0056-3398) stated that North Dakota lignite has a lower Cl content than subbituminous or bituminous coal and that Hg control from lignite is much more difficult, warranting a higher emission limit.

Response:

EPA concurs that lignite coal exhibits unique combustion and control characteristics and, as such, has placed lignite in a separate subcategory.

Comment:

Commenter OAR-2002-0056-5535 disagreed that the best-performing lignite units fire North Dakota lignite and that North Dakota lignite is significantly different from other lignite. First, the commenter's analysis of the best-performing units indicates that TXU's TNP-One unit, which burns Texas lignite coal, is the best-performing lignite unit. The commenter used EPA's methodology to estimate Hg emissions for every coal shipment fired by TNP-One. When these estimates are averaged, the average annual emission rate is 1.29 lb/TBtu – the best performance of any lignite-fired unit. Second, although it is true that Texas lignite has a higher ash content than North Dakota lignite and that facilities firing Texas lignite are among the biggest Hg emitters in the U.S., none of these facilities has opted to participate in any of the DOE-sponsored emissions tests aimed at evaluating Hg control technologies. The Monticello plant, which fires Texas lignite, is scheduled to be tested during the Phase II DOE tests (mid-2005), but the test plan excludes the most promising technology for lower ranks coals – halogenated activated carbon sorbents. Consequently, it will not be possible to compare Monticello's performance with that of North Dakota facilities, which have been tested with these sorbents, achieving Hg emission reductions in excess of 90 percent. In addition, the commenter noted that one facility firing Texas lignite – the Big Brown plant – has been operating a COHPAC baghouse for a number of years. This small add-on fabric filter is the key component of EPRI's patented TOXECON process, whereby activated carbon is injected upstream of the COHPAC. Tests of this configuration on low sulfur bituminous coal resulted in Hg capture averaging 86 percent over a 19-week period. Use of a COHPAC with a halogenated sorbent could result in very high Hg capture – even with Texas lignite – but, unfortunately, the test will not include this configuration. If EPA were to establish a more lenient standard for Texas lignites, it would have harmful environmental and health consequences. One outcome of a more lenient standard for these facilities is that they will continue to emit Hg in huge amounts. A second potential outcome of a higher emission rate – if EPA adopts its ill-advised trading scheme – is that these facilities might decide to reduce their Hg emissions using the most promising technologies, and then to bank and sell a large number of Hg allowances, thereby allowing other polluters to avoid controls. Thus, convincing EPA that they are unable to control their Hg emissions (in the absence of any data substantiating that assertion) is clearly in the financial interest of these companies and against the interests of public health and welfare.

Response:

As noted earlier, EPA continues to believe that placing lignite in a separate subcategory is warranted but that further subcategorization into Fort Union and Gulf Coast lignites is not necessary. The revised new-source NSPS Hg limits incorporate data from both types of lignite and, thus, are believed to be representative and appropriate. Further, as noted earlier, EPA does not believe that Hg-specific control technologies are currently available for use as the

basis of a national Hg standard. We believe that the declining cap under the cap-and-trade approach being finalized will ensure both development of the emerging Hg-specific control technologies and continued Hg emission reductions by all utility units in the most efficient manner.

3.2.4.6 Coal Refuse-fired Units

Comment:

One commenter (OAR-2002-0056-2068) requested that the EPA not set emission limits for new and existing coal refuse-fired plants so as to ensure that any limit is achievable and takes into account the wide variability within this important fuel supply.

Response:

The current subpart Db emission limits for PM, SO_2, and NO_x, are applicable to coal refuse-fired units (with an existing definition of "coal refuse") and EPA sees no basis to exclude such units from the Hg emission limits. EPA believes that the revised new-source NSPS Hg emission limits for these sources are achievable and appropriate.

Comment:

Three commenters (OAR-2002-0056-1766, -2162, -5495) opposed the proposed emission limits for coal refuse-fired units. The proposed limits are more than five times more stringent, on a lb/TBtu basis, than the proposed limits for the next most stringently-regulated coal-fired source category. The EPA selected this proposed standard based upon limited data from only two waste coal-fired sources. Such an insignificant amount of data is an insufficient basis upon which to promulgate emission limits. Also, the EPA did not appropriately consider the variability inherent in the waste coal fuel source. Specifically, the characteristics of waste coal vary to a much greater extent than other coal ranks. Finally, the commenters stated that in addition to being inequitable and based on inadequate data, the proposed emission limit for waste coal-fired sources may not be achievable. Commenter OAR-2002-0056-5495 thought the measured emissions from the test data used to set the limit were abnormally low due to a variety of factors.

Response:

The revised emission limits (as noted earlier) for coal refuse-fired units are based on data from units within the coal refuse subcategory. EPA believes that the stringency of the limits accurately reflects the performance on Hg emissions of controls used on such units. No data were provided during the public comment period that refuted the relative levels of control achievable by coal refuse-fired units as evidenced by the Hg emission limits established in the rule. Further, EPA did consider the variability inherent in the fuel source in arriving at the final emission limits. EPA disagrees with the commenters regarding the level of variability found in coal refuse related to other coal ranks. Some constituents (e.g., ash, Btu content) do exhibit

wider variability, as would be expected given the nature of the fuel source. However, other constituents (e.g., sulfur, Hg) exhibit similar or less variability than do other coal ranks.

Comment:

One commenter (OAR-2002-0056-2261) stated that the emissions limits for coal refuse-fired units must be consistent with the current levels of Hg emissions from each of these sources to ensure that all coal refuse-fired sources could comply with such levels, notwithstanding the inherently variable characteristics of the waste coal source. The commenter recommended that any such limit should be reflective of a 90 percent reduction in Hg, based upon the Hg content in the coal refuse prior to combustion, as measured by inlet and outlet concentrations evaluated during biennial performance testing. The commenter stated that such a limit would be consistent with the effective Hg control achieved by coal refuse sources.

Response:

EPA sees no basis for providing coal refuse-fired units a different compliance approach than for other subcategories. Therefore, the 12-month rolling average and continuous monitoring requirements have been maintained in the revised standards. The revised standards are believed reflective of the expected performance of coal refuse-fired units.

Comment:

One commenter (OAR-2002-0056-3560) stated that the EPA did not gather information concerning a non-CFB unit that burns coal refuse. Therefore, the proposed Hg emission limit for coal-refuse units cannot be justifiably applied to a cyclone unit burning at least 25 percent coal refuse and the rest of the fuel input is essentially bituminous coal.

One commenter (OAR-2002-0056-2826) points out that their member electric cooperative burns Illinois basin bituminous waste coal. Along with their electric cooperative, the commenter believes that EPA's data from units burning waste coals and the EPA's related analysis are neither complete nor representative of the emission characteristics of this coal rank. The commenter adds that there is apparently no information in the EPA database for a cyclone unit, such as their member cooperative's Unit 4, which burns a coal waste product as a significant portion of its fuel input. The commenter respectfully requests that EPA address the above issues as it finalizes its proposed rule.

One commenter (OAR-2002-0056-2261) observed that the proposed rules establish Hg emission rates based on rank of coal, including waste coal, being burned. The commenter does not believe that the rates for existing and new units are reflective of either new or existing technology used to burn waste coal. According to the commenter, EPA must consider:

(1) the difference and variation in the chemical quality of waste coal from different coal fields in different parts of the country;

(2) the technology used to clean the coal producing the waste coal;

(3) the percent SO_2 reduction required at the different waste coal plants and its impact on heat input and Hg emissions; and

(4) NO_x controls being implemented.

Response:

Such data as noted by the commenters (e.g., non-CFB units burning coal refuse; data on coal refuse from different parts of the country) were not made available to EPA during the public comment period. Units co-firing coal refuse and other coal ranks would be subject to the provisions applicable to units that blend coal ranks. EPA believes that future units constructed to combust coal refuse will be similar in nature to existing units and, thus, that the final emission limits are reflective of units that will combust coal refuse.

3.2.4.7 IGCC Units

Comment:

One commenter (OAR-2002-0056-2721) stated there has not been a full-scale demonstration of sorbent bed technology on IGCC units with lignite or subbituminous coal. The commenter noted that the process addressed by EPA in the preamble for the proposed rule is for an industrial facility firing bituminous coal and producing a synthetic gas (syngas) that is cooled to about 100 °F. According to the commenter, not all IGCC units have a gas stream with a temperature that low. The commenter stated that sorbent beds do not work when temperatures are several hundred degrees. The commenter believes there is no justifiable basis to use this technology for setting. performance standards.

Response:

EPA agrees with the commenter that no IGCC unit utilizing syngas produced from subbituminous or lignite coals has been operated with a carbon bed for Hg removal. However, IGCC units have been operated on subbituminous and lignite coals in the U.S. (OAR-2002-0056-5684). Application of the carbon bed to IGCC units burning such coals would not present any additional technical obstacles. EPA also concurs that the optimal temperature for carbon bed utilization is around 100 °F. However, EPA disagrees with the commenter's inference that this temperature is not found in some IGCC applications. The DOE conducted a feasibility study to evaluate the cost of removal of Hg from IGCC units (OAR-2002-0056-5685). This study found that the optimal location for the carbon bed was between the fuel gas cooling/knockout unit and the acid gas removal unit (and prior to the combustion turbine), a location likely to be found in any new IGCC installation. This location affords temperatures close to the optimal 100 °F. Therefore, EPA believes that carbon bed technologies are appropriate for use on new IGCC installations.

Comment:

One commenter (OAR-2002-0056-3459) stated that ACI should be the basis of the standard for IGCC units. DOE has concluded Hg controls are available and applicable to IGCC units. The technology is already commercially demonstrated to remove greater than 90 percent Hg removal and was specifically applicable to gasification systems using high-temperature slagging gasifiers and bituminous coal, which includes both of the IGCC plants currently in operation. EPA must establish emission limits that reflect at least 90 percent reduction in Hg emissions from IGCC units. Based on commenter's analysis, the rate should be 0.49 lb/TBtu or 3.9×10^{-6} lb/MWh (output-based standard based on 42.5 percent efficiency and conversion factor for mass/10^{12} Btu to mass/MWh at 42.5 percent efficiency is 8×10^{-6} TBtu/MWh).

Two commenters (OAR-2002-0056-1852, -2160) opposed separate limits for new or existing IGCC units. According to one commenter (OAR-2002-0056-2160), Hg capture from syngas has been proven to be readily available and inexpensive at the Eastman Chemical coal gasification plant in Kingsport, TN. There is no reason to establish separate and overly lenient limits for the two existing U.S. plants or for any new plants.

Response:

The existing units will be covered under the cap-and-trade portion of the final CAA section 111 rulemaking and, thus, will be subject to their respective State's Hg budget. Any new units would be subject to the more restrictive new source NSPS Hg emission limit which is based on the use of a carbon bed as at the Tennessee facility.

Comment:

One commenter (OAR-2002-0056-4139) stated that the WEST Associates statistical model should not have been applied in developing the emission limits for IGCC units. Both Cl and Hg would be removed separately from the coal as part of the coal gasification process. Therefore, Cl and Hg could not interact as they are not present at the same quantitative levels as in the combustion process of coal-fired boilers. This leads to an artificially high limit for new sources.

Response:

Analysis of variability is appropriate for IGCC units. It is true that Hg and Cl would be removed separately in an IGCC process; however, based on information available to EPA (OAR-2002-0056-5685), the Hg would likely be removed prior to the removal of the Cl, and, thus, the Hg-Cl interaction presumed in the current statistical analysis would still be valid.

3.2.4.8 Blended Fuel-fired Units

Comment:

One commenter (OAR-2002-0056-2198) stated that the proposed limits for subbituminous coal are less stringent than those for bituminous coal. A unit that previously burned bituminous coal could choose to blend or switch to subbituminous coal and emit more Hg proportional to the ratio of subbituminous to bituminous coal. Because many units can burn either of the two ranks of coal, this commenter does not support this approach. The EPA should require sources that burn a blend of coal to be subject to the more stringent limit regardless of the coal or coal mixture being burned at any time.

One commenter (OAR-2002-0056-2889) stated the proposed rule would allow units that blends coal ranks to average the standards for those coal. Facilities must compute the weighted average limit based on the proportion of energy input (Btu) contributed by each coal rank burned during the compliance period. However, the rule does not specify how this is to be done. Because blending is typically done with a bulldozer, the quantity of each fuel is not determined with any precision. To avoid inaccuracies inherent in computing a limit for blended coal, the rule should require the facility to meet the most stringent standard of the fuels combusted.

One commenter (OAR-2002-0056-3449) stated that limits for blended coals should not be prorated. Under the proposal, 50/50 blending of subbituminous coal with bituminous coal would increase allowable emissions for a facility previously burning only bituminous coal by almost 2 times. This type of coal blending is already popular for reducing SO_2 and NO_x emissions; the additional benefit of lower Hg emissions coupled with a higher limit would further increase the incentive. The fact that coal blending provides the benefit of a higher limit is a clear rationale that EPA should adopt one limit for subbituminous and bituminous coal. At the very least, the lowest applicable standard should apply to blended coal, not a prorated higher standard. The commenter's experience demonstrates that blended coal does not need a higher limit. Blending should be encouraged to reduce emissions, not increase allowable emissions.

Response:

EPA believes that it is appropriate to use the prorated approach as this is consistent with that already included in subpart Da.

Comment:

One commenter (OAR-2002-0056-2247) disagreed with EPA's description of the importance of coal rank at units such that fuel switching will not occur. Given the demands of further NO_x and SO_2 reductions, fuel switching will continue, the EPA's proposal to proportion the Hg emissions limit between subbituminous and bituminous (or between subbituminous and lignite) will result in emissions increases for the unit that switches. Rather than apportioning the limit between the percent of fuel burned, the limit should apply for the fuel used in the majority. Thus, any facility using up to 50 percent bituminous coal with subbituminous coal should meet a

limit for bituminous coal. Because subbituminous coal has lower overall Hg content and bituminous appears to have sufficient Cl or oxidize Hg for downstream capture, a unit blending coal should not have difficulty meeting the limit.

Response:

EPA believes that it is appropriate to use the prorated approach as this is consistent with that already included in subpart Da.

Comment:

One commenter (OAR-2002-0056-2897) believed blending of different coal ranks can also be readily accommodated under a rule that includes subcategorization. Of the two options presented, the commenter recommended that the EPA proceed with a weighted average standard, as this will be less susceptible to "gaming."

One commenter (OAR-2002-0056-2922) supported EPA's decision to utilize a blended emissions limit rather than attempt to establish a separate subcategory for blended fuel units, or to classify a unit based on the predominant coal it combusts.

One commenter (OAR-2002-0056-2900) urged EPA to retain the five subcategories identified in the proposal. The commenter stated that the failure to do so would have an immediate impact on the balance of coal ranks burned in the U.S. and would jeopardize the nation's fuel diversity. For the same reasons, the commenter supported the Agency's proposed approach of addressing units burning blended coal by weighting the applicable Hg limit according to the amounts of the different coals that are burned.

One commenter (OAR-2002-0056-2922) supported EPA's decision to utilize a blended emissions limit rather than attempt to establish a separate subcategory for blended fuel units, or to classify a unit based on the predominant coal it combusts.

Response:

EPA concurs with the weighted average approach endorsed by the commenters.

Comment:

One commenter (OAR-2002-0056-2900) supported the EPA's proposed approach for a unit burning a blend of coals and a supplemental fuel that the supplemental fuel would not be taken into account for purposes of determining the unit-specific emission limit that the unit must meet. However, the supplemental fuel's heat input and Hg emissions would be considered in determining the unit's compliance with the emission limit. The commenter requested that the regulatory text clearly reflects EPA's preamble language on this issue. In addition, the commenter requested that EPA clarify that units burning a single coal rank and a supplemental fuel would be treated the same as units burning a coal blend and a supplemental fuel. That is,

the supplemental fuel would not be considered in determining the emission limit to which the unit is subject. The commenter explains the unit would be subject to the emission limit for the coal rank it is combusting; however, for compliance purposes, the heat input and Hg emissions from the supplemental fuel would be taken into account.

Response:

EPA believes that the final regulatory language is clear.

Comment:

One commenter (OAR-2002-0056-3517) pointed out that there has been little in-depth study of plants that burn coal blends, and how that might impact or benefit Hg removal. The commenter stated that a case in point is the Valmont Plant in Colorado which burns a blend of low Hg, low Cl bituminous and subbituminous coal, both of which are mined in Colorado. According to the commenter, although it is recognized that these coals are low in Hg, there is still significant Hg reduction that occurs. The commenter request that EPA seek further information on coal blending as a potential option in addressing Hg reductions between the close of the comment period and the issuance of the final rule. The commenter stated they would like to retain the option to provide additional information on this topic as it becomes available.

Response:

The impact of intentional coal blending for the purpose of Hg removal is being investigated under the DOE Hg research program. EPA believes that this approach is yet another option that facilities may have in achieving compliance with the final emission limits.

Comment:

Two commenters (OAR-2002-0056-1848, -2108) expressed concern about compliance burden on sources that blend coal and the State agencies that regulate them. According to the commenters, there are no industry-wide blending procedures and the lack of specificity will lead to an inaccurate accounting of emissions.

Response:

EPA believes that the States are familiar with the weighted average approach being used in the final rule as it is currently a part of subpart Da for other pollutants.

3.2.4.9 Cogeneration Units

Comment:

One commenter (OAR-2002-0056-2906) stated that the proposed emission rate calculation for cogeneration units appears to unfairly penalize these units for sales of any electric

power less than the full generation capacity, contrary to the EPA's stated intent to advance the application of cogeneration facilities and thereby improve the nation's energy efficiency and achieve greenhouse gas emission intensity reductions. In both the proposed rule and preamble, EPA applies the 18 CFR 292.205 efficiency methodology to cogeneration facilities (implied to be limited to solid fuel-fired facilities because gas-fired units are not included in the rule applicability) (69 FR 4696 and 69 FR 4762). Application of that methodology appears to penalize those cogeneration facilities that sell only a portion of their total net electricity generation output to the grid. Irrespective of the comments relating to the need for annual net sales of electricity to the grid, the EPA approach would restrict the total output of energy in the denominator to only that electricity sold to the grid plus one-half of the net steam output of the unit, assuming that any energy input that is not utilized through electricity sales is used as steam output (69 FR 4762). However, this penalizes a facility for using any electricity generated in the cogeneration facility within the manufacturing facility. Many cogeneration facilities are located within manufacturing plants that use most, or all of the generated electricity. The cogeneration unit only sells to the grid the excess power on an as-available basis in order to maintain optimum overall system efficiency. For example, the methodology in the proposed rule was applied to a typical coal-fired cogeneration facility. At a constant Hg lb/hr emission rate, constant heat input to the boiler, and constant electricity generation rate, the calculated emission rate on a lb/MWh basis would vary with the quantity of electricity sold to the grid. For this example, the lb/MWh calculated emission rate would be 70 percent higher when selling 25 MWe to the grid than when selling 100 percent of generated electricity to the grid. This equation unfairly penalizes cogeneration facilities. The EPA needs to provide full consideration of the complexities of cogeneration units when trying to develop and utilize output based emission limits. An equitable and workable solution would be to follow past EPA practice in establishing emissions standards and allow cogeneration facilities the ability to use input based emission limits and calculations. With this approach, the boiler, fuels, and emissions controls will determine compliance without the apparent emission rate being unfairly skewed by the portion of electricity sold to the grid. The EPA should establish emissions standards that encourage installation and operation of highly efficient cogeneration facilities, and recognize their inherent variability in design and operating profiles versus typical single use electric utility units.

Response:

The commenter appears to believe that, for a cogeneration unit classified as a utility generating unit, reducing the percentage of electricity sold to the grid increases the emission rate for regulatory purposes. The commenter provided no calculations to support this contention, but, in any event, we believe the comment to be incorrect. If a unit's entire rated output is sold to the grid, the unit would be charged with emissions equivalent to full load. If the unit sells half of its rated output to the grid and the other half is used internally (either as steam or as electricity), the unit would be charged only 75 percent of its entire emissions output (all of the emissions from the 50 percent sold to the grid plus half of the emissions from the remaining energy used internally, or 25 percent, which totals 75 percent.

The boiler emits Hg for all the coal burned, whether the output is sold or used internally. EPA's proposed rule was formulated to be consistent with State implementation plan (SIP) rules

for NO_x emissions under the provisions of the Acid Rain program and with the revised NO_x emissions limits under subpart Da.

Comment:

One commenter (OAR-2002-0056-2913) stated that the proposed output-based limits should be modified to take into account the Hg emissions resulting from the combustion of fuel for co-generating steam for uses other than electricity production.

Response:

The commenter implies that no emissions limit exists for fuel burned to produce steam not used for electricity sold to the grid. This assertion is incorrect. Emissions from fuel used for cogenerating steam are generated at the same time as those emissions resulting from fuel used for electricity generation. However, for purposes of determining the "output" from the unit, credit for the steam is given a 50 percent credit, versus 100 percent credit for electricity. As stated earlier, this policy is consistent with SIP rules for NO_x emissions under the provisions of the Acid Rain program and with the revised NO_x emissions limits under subpart Da.

3.2.5 Emissions Limit Averaging Period

Comment:

Many commenters (OAR-2002-0056-1803, -1969, -2067, -2365, -2535, -2634, -2661, -2721, -2827, -2867, -2900, -2918, -2922, -3403, -3432, -3444, -3463, -3478, -3509, -3513, -3514, -3539, -4891) supported EPA's proposal to determine compliance with emissions standards based on a 12-month averaging period. Reasons cited by the commenters included:

(1) the large variability in coal Hg content. plant operations, and control technology performance;

(2) Hg is not an acute health hazard and concerns about Hg arise from long-term chronic exposure; and

(3) the compliance period would provide greater certainty that units will consistently meet the limits, particularly given that operational and material-related variability beyond the control of the owner/operator can impact emission levels.

Response:

EPA concurs with this comment.

Comment:

Several commenters (OAR-2002-0056-1969, -2260, -2721, -2830, -2835, -2850, -2918,

-3449) supported using a 12-month averaging period but disagreed with using the proposed averaging method for computing the 12-month average based on averaging monthly average. Instead, the commenters recommended that the averaging method be revised to a simple average of all valid hourly data from the previous 12 months. The commenters stated that this revision would equally weight all valid data over the 12-month period. The proposed rolling monthly average calculation method would place disproportionate weighting on hour values in months that include extended periods of lower loads, load following, or other operational variances.

Response:

To address the commenters' concerns, the final rule requires the 12-month rolling averages to be computed on a weighted basis. The rule requires valid Hg emissions data to be obtained for at least 75 percent of the unit operating hours in each month in which the unit operates. For each operating month, a monthly average Hg emission rate is calculated, which weights all of the hours of valid data equally. However, when the 12-month rolling average is calculated, each monthly average Hg emission rate is weighted according to the number of valid hours of data collected in that month. This ensures that the Hg emission rate for a month with few unit operating hours is not counted the same as the emission rate for a month in which the unit is in continuous operation. For any month in which less than 75 percent of the Hg emission data is captured, the rule requires a substitute Hg emission rate to be reported, and in the rolling average, the substitute emission rate is weighted according to the number of unit operating hours in that month.

Comment:

One commenter (OAR-2002-0056-3210) objected to the 12-month average compliance determination because it further weakens the proposed standards. The purpose of the 12-month average is to adjust for variability in the process, fuel source, etc. However, variability is already overstated in the proposed emission limits resulting in many units being able to avoid controls. The 12-month average would be acceptable if the proposed standards were significantly more stringent.

Response:

EPA disagrees that the 12-month rolling average format weakens the standards. Further, as noted above, the new-source emission limits have been revised which may also address the comment.

Comment:

Two commenters (OAR-2002-0056-2835, -2922) noted that 40 CFR 60.50a(h)(1), which covers calculation of mass Hg emissions from Hg CEMS and Method 324, calls for calculating the "arithmetic average of all weekly emission rates for [Hg] for the 12 successive calendar months." Subsequent subsections refer to calculation of Hg mass emissions "over a month" from CEMS and over the "emission rate period" from Method 324. It is not clear why 40 CFR

60.50a(h)(1) refers to calculation of weekly rates or how those rates fit into the more specific calculations. The EPA needs to correct this discrepancy.

Response:

Proposed Method 324 has been renamed as appendix K to 40 CFR part 75 and the method and regulatory text has been clarified.

Comment:

One commenter (OAR-2002-0056-2889) stated that a correction is needed is 40 CFR 60.45a(a). This section refers to a 12-month rolling average and conflicts with 40 CFR 60.45(a)(5) which refers to a monthly limit.

Response:

The commenter is correct in that the compliance monitoring period is based on a 12-month rolling average. However, in order to arrive at this average, monthly averages must be established on a continuous basis. Thus, EPA believes that 40 CFR 60.45(a)(5) is correct as stated.

3.2.6 Emissions Averaging

Comment:

Several commenters (OAR-2002-0056-2634, -2830, -2835) requested that the EPA include facility-wide averaging in the section 111 Emission Guidelines for existing sources as an additional compliance alternative. States should be encouraged to allow such flexible compliance alternatives if states decline to adopt a section 111 trading program, if that option is selected by the EPA. By including this type of flexibility mechanism, the EPA will ensure that those facilities located in States opting out of the trading program will retain some degree of flexibility when complying with the requirements of the Emission Guidelines. Similarly, facility-wide emissions averaging provides a flexible compliance alternative to a cap-and-trade program in the event that neither cap-and-trade option can be authorized under the statute. Varying operational modes or combination of systems, e.g., wet/dry scrubber, ESP or fabric filter, could be employed to provide the greatest potential to economically reduce Hg emissions to meet compliance requirements.

Response:

States and Tribes are free to allocate their Hg budgets as they see fit, whether they participate in the nationwide trading program or not, as long as the reductions are achieved from coal-fired Utility Units. We believe that this will address the commenter's concerns.

Comment:

Several commenters (OAR-2002-0056-2900, -3432) supported allowing facilities with both industrial boiler units and coal-fired utility units to opt the industrial boiler units into the electric utility rule for purposes of meeting the emissions standard. The commenter believes a final rule should allow affected facilities with both industrial boilers and coal-fired utility units the compliance flexibility to meet one Hg emission limit through facility-wide emissions averaging.

Response:

Industrial boilers that do not meet the definition of an "electric utility steam generating unit" under either 40 CFR part 60, subpart Da or HHHH will not be subject to the final rule. Therefore, facility-wide emissions averaging between such units and Utility Units will not be allowed.

Comment:

One commenter (OAR-2002-0056-2922) supported EPA's proposal to allow emissions averaging as a compliance option for two or more coal-fired units, including blended coal units, that are located at a single contiguous. However, the commenter suggested the following clarifications to provide for smooth implementation of averaging plans. First, one situation under which sources might wish to utilize averaging is where two or more units utilize a common stack. Common stack monitoring is allowed under the general provisions as long as the "monitoring is sufficient to demonstrate compliance with the relevant standard." However, the proposed rules do not make clear under what provision such units should report and whether EPA expects sources to submit averaging plans for such units. The EPA should revise the rule to address that point.

One commenter (OAR-2002-0056-3398) recommended extension of emissions averaging to all units under common control within a State to add flexibility.

Two commenters (OAR-2002-0056-1608, -2922) recommended that a Multi-Source Averaging Plan (MAP) to meet the Hg emission standards be based on the existing CAA Title IV NO_x program. Although this approach for Hg averaging would benefit larger utility systems, it is of far less benefit to small systems. Instead, it could be altered to allow averaging among different owners and operators. The CAA Title V permit program could serve to ensure multi-source compliance after a MAP is approved by EPA. Additionally, the MAP approach could be extended across state lines as appropriate, as is done in the CAA Title IV NO_x program.

Response:

EPA believes that the cap-and-trade approach being finalized will adequately address the comment.

3.3 VARIABILITY

Comment

EPA used a similar variability methodology to calculate the new-source NSPS limits as it did to select the MACT floor limits; the only difference is that it did not apply the inter-variability analysis. Thus, several of the commenters' concerns also apply to the selection of new source NSPS limits.

Many commenters explained that EPA improperly used a short-term worst-case analysis to develop a long-term standard (12-month rolling average). EPA chose the 12-month rolling average emission limit format and then applied the industry's variability method to account for coal composition. The EPA's own variability analysis explained that it was inappropriate to apply its variability analysis where a long-term compliance period is allowed. Commenter OAR-2002-0056-2878 stated that, given the long-term format, there is no need for the industry's variability analysis; the 12-month averaging time provides more than enough buffer to address the worst foreseeable circumstances.

Commenter OAR-2002-0056-3459 stated that although EPA acknowledged that one method for dealing with variability was the length of the compliance period, EPA did not assess that option. Instead, EPA added an annual averaging time on top of is inflated variability approach and attempted to justify this double counting by stating that Hg poses a chronic and not acute health risk. Whether or not this justification is warranted, EPA neglected the effect of using a long-term standard on the stringency of the standard. And because EPA proposed to determine compliance using a long-term average, the compliance status of the unit will be unaffected by short-term fluctuations in the coal characteristics of coal shipments and control equipment.

Commenter OAR-2002-0056-2920 stated that EPA must specifically explain why the 12-month averaging period is necessary and appropriate.

After applying the industry's variability analysis, EPA calculated the emission rate over the full range of coal compositions presumed to be used and sorted those emissions to obtain a cumulative frequency distribution and selected limits based on the 97.5 percentile (compared to the 95 percent in the WEST analysis). Many commenters (e.g., OAR-2002-0056-2920) noted that EPA provided no rationale for selection of the 97.5 percentile. This violates the CAA, is inconsistent with EPA's own guidance and past practices, and improperly results in emission limits that are many times higher than appropriate or allowed under State permits. Commenter OAR-2002-0056-3459 recommended that EPA use the mean calculated emissions from annual coal data rather than the 97.5 percent upper confidence limit of the mean. The arithmetic mean is consistent with the 12-month rolling average and consistent with EPA policy.

Commenter OAR-2002-0056-3449 criticized EPA's failures to consider data on management of Hg variability from operating facilities.

Two commenters (OAR-2002-0056-2920, -3449) criticized in detail EPA's equations based on coal Cl content. EPA has not established a valid statistical relationship between Hg removal and coal Cl content.

State (e.g., OAR-2002-0056-2660, -2823, -2889, -3210, -3449) and environmental group (e.g., OAR-2002-0056-3459) commenters asserted that EPA has not established a valid statistical relationship between Hg removal and coal Cl content. Analyses conducted by WEST and DOE demonstrate that there is indeed a valid correlation, particularly with respect to units equipped with a fabric filter/spray dryer combination. To the extent coal rank is indicative of Cl content, coal rank may be an important factor with respect to the Hg removal fraction as the New Jersey Department of Environmental Protection suggests. However, the New Jersey Department of Environmental Protection incorrectly asserts that EPA should have used raw data rather than average Cl concentrations to develop its Equation (5). EPA's approach properly relies on average values because they provide less uncertainty as compared to raw data alone.

Commenter OAR-2002-0056-5498 provided detailed supplemental comments that address criticisms of EPA/DOE's variability analysis. Their comments explain why EPA's analysis is both consistent with the CAA as interpreted by the D.C. Circuit and scientifically sound.

One commenter (OAR-2002-0056-2835) stated that the variability factors used by the EPA in the proposal are appropriate.

Response:

EPA continues to believe that accounting for variability is required in the establishment of national emission standards. However, EPA concurs with those commenters who indicated that we had overstated the variability by using both a rigorous statistical analysis and a 12-month rolling average for compliance. Our revised analysis of the data and new-source selection procedures are described elsewhere in this document. We believe that this adequately addresses the variability.

3.4 COAL ANALYSIS

Comment:

One commenter (OAR-2002-0056-3546) stated that the proposed rule does not specify protocols for determining rank classification of the coal burned in a unit. The EPA needs to propose a methodology for establishing and reporting coal rank classification for determining which of the emission limits is applicable to a given unit. The commenter asked if coal ranks will be based on coal samples taken at the mine or upon delivery point at the power plant, and who is ultimately accountable for conducting the ASTM coal rank tests; the supplier or the power plant owner/operator.

Response:

It is the owner/operator that is ultimately responsible for compliance with the final rules. How he/she chooses to comply, however, is not specified. EPA believes that facilities are currently contracting for a certain rank of coal with specific properties best suited for the given boiler and, thus, are well aware of the rank of coal being utilized. EPA believes that reliance on the ASTM coal rank classification scheme is appropriate for this rule as it is a commonly accepted means of ranking coals.

Comment:

One commenter (OAR-2002-0056-1969) stated that the proposed rule does not specify fuel measurement/sampling method required to determine the Btu input contributed by each coal rank. The commenter recommended that EPA should make it clear that sources can use procedures already in place at the source for recording fuel type and monitoring fuel consumption.

Response:

The final rule does not require fuel measurement or sampling. Further, there are no specifications for fuel consumption monitoring procedures so the facility may continue to use procedures already in place.

3.5 NOTIFICATION, RECORDKEEPING, AND REPORTING

3.5.1 Recordkeeping

Comment:

One commenter (OAR-2002-0056-3543) stated that regardless of the approach taken, the requirements for emissions testing and recordkeeping must be sufficient to provide data for development of TMDL. These requirements will provide a rich source of data and should not be weakened.

Response:

EPA has not weakened its monitoring or recordkeeping requirements.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2922) stated that the preamble indicates that sources will be required to maintain monthly records of types of fuel burned, total fuel usage, and fuel heating value, but these requirements do not appear in the proposed rule. EPA should add a provision for recording those values consistent with existing company practices.

Response:

EPA believes that the final rule addresses the commenter's concerns.

3.5.2 Notifications and Reporting

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2922) stated that section 63.10030(e) states that a "Notification of Compliance Status" must be submitted for each "performance test" or "initial compliance demonstration" as specified in section 63.10007. Section 63.10007, however, only covers performance testing for "oil-fired" units. Initial compliance demonstrations for coal-fired units are addressed in section 63.10009. If EPA intends a "Notification of Compliance Status" to be submitted by coal-fired units following the first 12-month period, a reference to section 63.10009 should be added. If EPA does not intend for coal-fired units to submit that notice, the reference to the "initial compliance demonstration" should be removed or clarified.

Several commenters (OAR-2002-0056-2634, -2718, -2922) stated that section 63.10030(a) requires compliance with many notices in the general provisions, including the "Notification of Compliance Status" in section 63.9(h). That requirement is confusing given that section 63.10030(e) sets out requirements for "Notification of Compliance Status" that are narrower than those in section 63.9(h) (e.g., section 63.10030(e) only requires compliance with section 63.9(h)(2)(ii)). EPA should review these provisions and address the inconsistencies and overlapping requirements to better explain to sources what is required in each applicable notice or report. Section 63.10030(a) also requires compliance with section 63.6(h)(4) and (5). However, according to Table 4, those provisions, which relate to opacity and visible emissions observations are not applicable. As a result, they should be removed from section 63.10030(a).

Response:

Part 60 does not have a requirement for a Notification of Compliance Status. The proposed amendments to subpart Da require for Hg and Ni emissions that the performance test data from the initial and subsequent performance test and from the performance evaluation of continuous monitors be submitted to the Administrator. Subpart Da also requires semiannual reports indicating whether: (1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified. (2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance. (3) The minimum data requirements have or have not been met: or, the minimum data requirements have not been met for errors that were unavoidable. (4) Compliance with the standards has or has not been achieved during the reporting period. Therefore, subpart Da with the proposed amendments would require that performance tests and semiannual compliance reports be submitted for both oil- and coal-fired units. Regarding the reference to the requirement to comply with section 63.6(h)(4) and (5), 63.6 (h) deals with compliance with opacity and visible emission standards.

Section 60.48a in subpart Da with the proposed amendments does not have any compliance provisions for opacity and visible emission standards. Therefore this comment does not apply to the part 60 standards.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2922) stated that section 63.10009(d)(4) requires reporting of the 12-month rolling average Hg emissions rate in the "first semi-annual compliance report." If the initial semi-annual report will be submitted before 12 months of data have been collected, as section 63.10031 requires, it is not possible to report a 12-month rolling average. EPA should remove this requirement and clarify how and when results are to be reported (e.g., first in the initial "Notification of Compliance Status" and thereafter in the next semi-annual report).

Response:

This comment does apply to reporting of compliance with the Hg emission limit. Compliance cannot be determined until 12 months of data are available. This has been addressed in MACT standards with emission rates that are 12-month rolling averages, such as subpart SSSS (the NESHAP for Surface Coating of Metal Coil, see 68 FR 12591, March 17, 2003 for correction notice) as follows for new affected sources: (1) The initial compliance period begins immediately upon start-up or by (data of publication of the final rule in the FR) and ends on the last day of the 12th month following the compliance date. If the compliance date falls on any day other than the first day of a month, then the initial compliance period extends through that month plus the next 12 months. (2) The first semiannual reporting period begins 1 day after the end of the initial compliance period described in (1) that applies to your affected source and ends 6 months later.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2922) stated that table 2 in the proposed rule would require each coal-fired unit subject to a limit in section 63.9990 must demonstrate "initial compliance" by establishing "a site specific [Hg] limit according to the procedures in section 63.10009 and reporting the limit in your notification of compliance status." This articulation of the initial compliance demonstration is not consistent with the rules. Many units do not establish site-specific limits, and it is not clear how simply reporting a limit establishes compliance. Section 63.10009 does not call for reporting of a limit, but rather calculation of a 12-month rolling average. Also, there is no requirement in section 63.10030(e), addressing "notification of compliance status," to report the applicable limit

Response:

This does not apply to the proposed amendments to subpart Da. The Hg compliance provisions added as paragraph (m) to Section 60.48a specify how Hg emissions will be calculated using data measured as specified in Section 60.49a. There is no mention of establishing a site-specific Hg limit.

3.6 COMPLIANCE DATES

Comment

One commenter (OAR-2002-0056-3449) disagreed with the EPA's preamble statement that overly ambitious Hg mandates in the near term could actually hamper innovation toward more cost effective and less costly technologies (69 FR 4687). It is more likely that EPA's minimal reductions over the next decade would hamper innovation and improvement of public health. The sooner ACI with fabric filters or other control combinations are required, the sooner costs will drop. The costs are reasonably now and much less than the costs of Hg poisoning.

Response:

EPA stands by its position that Hg-specific control technologies are not yet commercially available and that the regulatory approach being finalized is the best approach to both effect significant SO_2, NO_x, AND Hg emission reductions while also encouraging the further development of the emerging Hg-specific technologies.

Comment:

One commenter (OAR-2002-0056-1969) stated the concern that the monitoring and recording technology has not evolved to the level of reliability necessary to collect continuous Hg emissions data for compliance purposes and to report those results consistent with EPA's proposed requirements.

Response:

EPA believes that the monitoring and recording technology is available and reliable at this time sufficient to show compliance with the final emission limits. However, further developments are sure to ensue in the coming years such that the commenter's concerns will be alleviated.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2922) stated that under proposed compliance date provisions are confusing and conflicting. Under 40 CFR 63.9983(a) and 63.10008(d), new units must (1) install and operate monitors, and (2) comply with the "emissions limitations and work practice standards" upon the later of publication of the final rule, or startup. Under Section 63.10005, sources then have 180 days after the date for compliance with "emissions limitations and work practice standards" in Section 63.9983, to complete all performance tests, selection of operating parameters, and monitoring equipment performance evaluations. Under Section 63.9983(b) and 63.10008(d), existing units must (1) install and operate monitors, and (2) comply with "emissions limitations" by 3 years after the final rule is published. Section 63.10005 states that performance tests, operating limits and monitoring equipment performance evaluations also must be conducted by the compliance date

in Section 63.9983 (i.e., 3 years from publication of the final rule), but done so according to the applicable provisions in section 63.7(a)(2), which (unlike section 63.9983) allows 180 days from the compliance date for performance testing (i.e., 3 years and 180 days after publication). For both new units and existing units, however, section 63.10009(d) states that "compliance monitoring" must begin on the "effective date of this subpart." For new units, the requirement to "comply" with "emissions limitations and work practice standards" on the date of publication of the final rule and 180 days before the deadline for performance testing, Section 63.10005 makes no sense. Sources cannot be expected to comply without a performance test or monitoring system in place to establish compliance. For existing units, the rules also are in conflict as to whether an additional 180 days is allowed for performance testing, selection of operating parameters, and monitoring equipment performance evaluations. If the additional 180 days is provided, the deadline for compliance must also be extended. Moreover, for Hg, these provisions also fail to recognize that sources cannot establish compliance with the Hg emissions limitation until 12 months after the monitoring system evaluation has been completed and the required 12 months of compliance data have been collected. For both new and existing units, the requirement to begin "compliance monitoring" on the effective date of the rule, also makes no sense. It conflicts with the provisions in section 63.9983 establishing "publication" (not the effective date) as the triggering point, ignores the fact that some new units may not even have started-up, and ignores the additional 180 days that are supposed to be provided under section 63.10005. The EPA should follow the model in Part 75 and establish a deadline for applicability of the subpart and then a single deadline for installation, operation, and evaluation of monitoring systems and for performance testing and selection of operating parameters. For new units, the deadline for applicability of the rule would be the later of publication or unit startup. For existing units, the applicability date would be 3 years after the date of publication of the rule. The deadline for installation, operation, and certification of monitoring systems and for performance testing and selection of operating parameters (i.e., the point when "compliance monitoring" is begun) would be 180 days later. The deadlines for establishing compliance with the Hg standard should be the end of the initial 12-month compliance period. At the time of the demonstration of compliance for the initial 12-month period, sources would be deemed to be in compliance for the prior 12 months. As a result, they would at that time have met the statutory deadline for compliance.

Response:

Although the commenters cited concerns with the proposed MACT standard, which is not being finalized, EPA believes that their concerns may also have been valid for the proposed subpart Da revisions. Section 60.8 Performance tests of the General Provisions to part 60 requires that within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility... the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s). Therefore, a new facility has 180 days after initial startup or date of publication of the final rule to complete and report the results of the initial performance test. The timing of the initial compliance period and required reporting should be as follows: (1) The initial compliance period begins upon submitting the report of the initial performance test to the Administrator, but no later than 180

days after start-up or (data of publication of the final rule in the FR) and ends on the last day of the 12th month following the compliance date. If the compliance date falls on any day other than the first day of a month, then the initial compliance period extends through that month plus the next 12 months. (2) The first semiannual reporting period begins 1 day after the end of the initial compliance period described in (1) that applies to your affected source and ends 6 months later.

RESPONSE TO SIGNIFICANT PUBLIC COMMENTS ON THE PROPOSED CLEAN AIR MERCURY RULE

Received in response to:

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 4652; January 30, 2004)

Supplemental Notice for the Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 12398; March 16, 2004)

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources, Electric Utility Steam Generating Units: Notice of Data Availability
(69 FR 69864; December 1, 2004)

Docket Number OAR-2002-0056

4.0 PERFORMANCE STANDARDS FOR OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

US Environmental Protection Agency
Emissions Standards Division
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

15 March 2005

General Outline

4.0 PERFORMANCE STANDARDS FOR OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

4.1 NEED FOR REGULATION

Comment:

One commenter (OAR-2002-0056-2046) questioned the threshold decision to regulate nickel (Ni) emissions from oil-fired units at all. According to the commenter, based on what it termed conservative assumptions (i.e., assumptions that overstate the risk), EPA concluded in its 1998 Report to Congress on the emission of hazardous air pollutants (HAP) from oil-fired units that Ni emissions from these units were responsible for one excess cancer case every 5 years. According to the commenter, the Agency concluded in the same report that only 11 units in the country contributed to an excess maximum individual risk of cancer of one-in-a-million, but only barely so. The commenter provided updated information indicating that many of these units have changed their operations so as to drastically limit their oil use, or have shut down entirely. Moreover, the commenter added that there is information to suggest that EPA's assumptions regarding the toxicity of Ni emissions from oil-fired units were overly conservative. The commenter recommended that EPA re-evaluate its conclusion that these emissions warrant regulation at all.

One commenter (OAR-2002-0056-2828) stated that EPA should not set a MACT standard for Ni emissions from electric utility steam generating units because the cost/benefit ratio of the proposed MACT is exorbitant and EPA's risk assessment is extremely over-conservative and greatly overstates risks which are not significant. The commenter stated that EPA assumed that Ni emissions from electric generating units are 50 percent Ni subsulfide although a more realistic estimate based on data that became available to EPA after the Report To Congress was issued indicates that the level of Ni subsulfide in electric utility emissions is far lower than even 10 percent, and may actually be 0 percent.

The commenter noted that in the proposed rulemaking, EPA asked for comment on the finding in the Utility RTC that only 11 of 137 oil-fired utility units considered in the Utility RTC posed an inhalation risk to human health of greater than one in one million. The commenter noted that this estimate is for the year 1990, for which it is estimated that a population of 110,000 would be exposed to a risk greater than one-in-one-million. The commenter further noted that in 2010, after imposition of the requirements of the Clean Air Act (CAA), EPA estimates that the population at risk decreases to 11,000 because several of the 11 units have already been converted to natural gas, are burning more gas or are shut down. According to the commenter, EPA did not specify which of the 11 units these are although it seems reasonable that the number of power plants would be substantially less than 11.

Regarding the cost-benefit calculation, the commenter stated that a cost benefit calculation using EPA's numbers shows a cost-benefit ratio of $2.08 billion dollars per avoided cancer case, clearly exorbitant and unjustifiable. According to the commenter, using more reasonable numbers for the percent of emissions that are Ni subsulfide would result in even

higher cost per avoided cancer.

One commenter (OAR-2002-0056-2504) stated that the scientific risk data does not support the need for regulating Ni.

One commenter (OAR-2002-0056-2891) stated that risks posed by Ni emissions from oil-fired generators are negligible and do not justify a finding that the regulation of such units is appropriate and necessary.

One commenter (OAR-2002-0056-3402) submitted that there is a serious question as to whether Ni emissions from oil-fired units should initially have been or should now be regulated at all, in light of evidence relating to the decreasing use of oil generation and the toxicity of Ni emissions. The commenter recommended that EPA re-evaluate its conclusion that these emissions warrant regulation at all.

One commenter (OAR-2002-0056-2850) supported exempting Ni emissions from oil-fired plants as there is no public health justification for developing regulations. According to the commenter, any actions taken by their industry that could raise the cost of electricity to consumers should bring commensurate health and environmental benefits.

One commenter (OAR-2002-0056-2452) noted that the power generation industry has changed significantly since EPA's 1998 Report to Congress. The commenter stated that updated data on the nation's oil-fired units and their operating characteristics are important to developing a sound final rule.

Response:

Based on the comments received, EPA has reexamined the available information relating to both the number of oil-fired units and the combinations of fuels fired in such units. Based on that reexamination, EPA believes that Ni emissions from oil-fired Utility Units have been substantially reduced since the 1998 Utility Report to Congress through a combination of unit closures and fuel switching. In addition to the information provided by the commenters, EPA analyzed the latest information provided by the U.S. Department of Energy, Energy Information Administration (DOE/EIA), particularly with regard to the 11 plants identified as causing the greatest risk. The 11 oil-fired plants identified in the Utility Study as having a cancer maximum individual risk of greater than 10^{-6} based on Ni emissions were comprised of 42 individual units. Of those 42 units, 12 units have permanently ceased operation or are out of service. (OAR-2002-0056-2046 at pp. 12 - 13; OAR-2002-0056-5998). In addition, 6 of the original 42 units have reported to the U.S. Department of Energy (DOE) that their fuel mix now includes natural gas. Earlier reports did not show these units as using natural gas as a fuel. (OAR-2002-0056-5998). The use of natural gas as a part of their fuel mix would decrease the Ni emissions from these 6 units. Similarly, another 5 units report using a mix of natural gas and distillate oil (rather than residual oil) in 2003. (OAR-2002-0056-5998). Since distillate oil contains less Ni than the residual oil previously burned by these units, it is reasonable to assume that these units currently emit less Ni than was previously the case. Another 2 units now fire a residual

oil/natural gas mixture and have limited their residual oil use through permit restrictions to no greater than 10 percent of the fuel consumption between April 1 and November 15, with natural gas being used for at least 90 percent of total fuel consumption. (OAR-2002-0056-2046 at p. 13). Finally, five units have effectively eliminated their mercury emissions since the Utility Study by switching to burning natural gas exclusively. (OAR-2002-0056-2046 at pp. 12 - 13; OAR-2002-0056-5998). Taken as a whole, these changes mean that 30 of the original 42 units identified in the Utility Study have taken steps to effectively reduce or actually eliminate their Ni emissions. Of the original 11 plants identified in the Utility Study, only 2, both in Hawaii, have units for which actions that will result in reduced Ni emissions do not appear to have been taken. ("Analysis of operating oil-fired electric utility steam generating units," OAR-2002-0056-6178). In addition to the closure of the 12 units identified as being of potential concern in the Utility Study, there has been a steady decrease in the number of oil-fired Utility Units generally over the past decade and this trend is likely to continue. In fact, the latest DOE/EIA projections (OAR-2002-0056-5999) estimate no new utility oil-fired generating capacity and decreasing existing oil-fired generating capacity through 2025, with an additional 29.2 gigawatts of combined oil- and natural gas-fired existing capacity being retired by 2025. Based on the foregoing, EPA concludes that it is not appropriate to regulate oil-fired Utility Units under section 112 because we do not anticipate that the remaining level of utility Ni emissions will result in hazards to public health.

4.2 OTHER

Because EPA, in the final rule, is not taking final action on the proposal to regulate Ni emissions from oil-fired units, we are not providing responses to the remaining comments received on the proposal to regulate such emissions.

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(69 FR 69864; December 1, 2004)

Docket Number OAR-2002-0056

5.0 MERCURY CAP-AND-TRADE PROGRAM

US Environmental Protection Agency
Emissions Standards Division
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

15 March 2005

General Outline

5.0 MERCURY CAP-AND-TRADE PROGRAM

5.1 GENERAL

5.1.1 Support cap and trade

Comment:

Many commenters (OAR-2002-0056-1046, -1475, -1482, -1483, -1608, -1623, -1625, -1673, -1692, -1768, -1790, -1802 -1826, -1834, -1859, -1889, -1900, -1955, -1961, -1969, -2042, -2115, -2117, -2119, -2123, -2135, -2162 -2172, -2204, -2221, -2224, -2228, -2229, -2232, -2243, -2260, -2323, -2346, -2356, -2375, -2428, -2431, -2597, -2610, -2613, -2718, -2729, -2826, -2833, -2835, -2841, -2844, -2845, -2850, -2861, -2883, -2895, -2897, -2899, -2900, -2904, -2906, -2907, -2911, -2915, -2918, -2929, -2948, -3199, -3208, -3211, -3431, -3432, -3440, -3443, -3445, -3454, -3463, -3469, -3478, -3516, -3517, -3521, -3522, -3530, -3531, -3537, -3539, -3546, -3556, -3565, -4103, -4132, -4385, -4454) supported the cap-and-trade option for controlling mercury emissions from coal-fired power plants.

One commenter (OAR-2002-0056-2906) also supported the cap-and-trade approach to controlling nickel emissions from oil-fired power plants.

Many commenters (OAR-2002-0056-1623, -1625, -1673, -1692, -1768, -1826, -1859, -1961, -1969, -2162, -2243, -2375, -2431, -2718, -2833, -2835, -2841, -2844, -2861, -2883, -2897, -2899, -2900, -2906, -2907, -2915, -2929, -3208, -3432, -3443, -3463, -3478, -3507, -3521, -3522, -3531, -3537, -3546, -3565) supported a cap-and-trade approach as being the most cost effective way of achieving substantial emission reductions from the electric power sector.

Many commenters (OAR-2002-0056-1046, -1475, -1482, -1483, -1623, -1834, -1889, -1900, -1955, -2117, -2115, -2117, -2135, -2224, -2323, -2346, -2718, -2841, -2904, -2906, -2929, -3199, -3211, -3443, -3516, -3531, -3539, -3546) cited larger emission reductions from cap and trade than from the traditional MACT approach as a reason they supported cap and trade.

Several of these commenters (OAR-2002-0056-1955, -2718, -3546) noted that greater environmental benefits would be achieved because of greater compliance within the regulated community and commenter 1955 cited the compliance rate of 99.93 percent with the Acid Rain Program for SO_2 in 2001.

Several commenters (OAR-2002-0056-4103, -4385, -2610, -2613, -2729, -2841) submitted that emission trading helps companies avoid potential problems that could reduce power reliability while improving the environment by providing faster and efficient emission reductions.

One of these commenters (OAR-2002-0056-2841) noted cap and trade would not result in increased demand for or pressure on natural gas prices because companies will be able to over control units that are most economic to control and leave smaller, lower emitting units on-line.

Several commenters (OAR-2002-0056-1834, -1889, -2117, -2123, -2323, -2907) stated that a nationwide cap-and-trade would reduce mercury emissions by almost 70 percent from 2001 levels, achieving the MACT goal by 2010 and capping emissions at 15 tons in 2018. The commenters noted that MACT would only reduce these emissions from coal-fired power plants by 29 percent from 2001 levels by 2007.

Several commenters (OAR-2002-0056-1623, -1768, -1859, -2162, -2375, -2597, -2833, -2835, -2844, -2850, -2900, -2907, -3432, -3440, -3522, -3531, -3537) believed cap and trade offers a flexible, market-based approach.

One commenter (OAR-2002-0056-3432) noted that compliance flexibility is especially important to small generating systems.

Several commenters (OAR-2002-0056-2597, -2845, -2897, -2906, -3431) believed that cap and trade will have less impact on fuel diversity and natural gas availability than the MACT approach.

One of these commenters (OAR-2002-0056-2845) noted fuel switching to meet the acid rain requirements resulted in the loss of many jobs. Several commenters (OAR-2002-0056-2224, -2597, -2900, -2904, -3530, -3537) submitted that cap and trade will spur technological innovations by electric generators seeking to create emission credits that can be sold and reducing emissions early in the process.

Several commenters (OAR-2002-0056-2900, -3537) added that cap and trade would result in a certain, fixed cap on emissions from affected sources and would create incentives for emissions reductions beyond those required by current regulations.

One commenter (OAR-2002-0056-1608) believed that a regulatory approach can work if it's designed around the following principles: 1) regulatory certainty that will allow our industry to make financially sound compliance and planning decisions regarding capital investments in environmental and energy technologies, 2) that EPA should set reasonable reduction targets and time lines, and provide maximum flexibility to minimize costs to achieve desired air quality objectives cost effectively through the use of flexible, market-based mechanisms such as emissions trading, and finally 3) to protect fuel diversity to preserve and assure the continued supply of reliable, affordable electricity to meet our nation's growing energy needs.

One commenter (OAR-2002-0056-3516) stated that criticism of the cap-and-trade option, in the mercury context, was inappropriate. The commenter noted a recent study from the Brookhaven National Laboratory (BNL) observed that, "A Cap and Trade program has the potential to be protective of human health while being more economically efficient than limiting releases from all power plants to a fraction of their current release rates." [Assessing the Mercury

Health Risks Associated with Coal-Fired Power Plants: Impacts of Local Depositions [PDF-866MB] presented by Terry Sullivan, BNL at http://www.netl.doe.gov/coalpower/environment/mercury/ .] The commenter noted further the BNL researchers challenged the alternative of a plant-by-plant approach to mercury control based upon risk considerations as follows: "The prediction that risks resulting from Hg emissions from coal-fired power plants are small for the general population and the fact that the risks are borne by a small fraction of the population suggests that placing reduction in mercury emission goals on a plant by plant basis will do little to improve human health. Therefore, a cap and trade approach appears to be acceptable from a risk standpoint."

Several Texas State representatives and local officials (OAR-2002-0056-2119, -2204, -2221, -2228, -2232, -2356, -2428) endorsed the cap and trade approach. They noted that Texas is the largest coal consumer (using over 40 million tons of lignite/yr) and the 5th largest coal producer; coal mining is an important part of the economy ($17 billion/yr). The commenters stated that mercury is difficult to remove from lignite and there are no commercially demonstrated technologies to remove the elemental mercury emitted from lignite. The commenters submitted that any regulations must not displace lignite coal in the fuel mix in favor of more costly natural gas.

Concerning the regulatory mechanism used for a mercury control program, one commenter (OAR-2002-0056-3454) recommended including flexible mechanisms in the regulation that would encourage innovation while providing a clear goal with meaningful reductions. Examples cited by the commenter of these types of mechanisms included early reduction incentives, market based approaches, capital recovery programs, plant wide averaging, safety valves or other approaches. The commenter stated these types of incentives combined with concrete goals would encourage technology innovation and reduce impacts on generation mix.

Many commenters (4,457 citizens, 3 public interest groups, 18 states, 1 tribe) generally supported the more flexible cap and trade approach because it would result in lower emissions for less cost than fixed emission reductions. The commenters stated this would be a reasonable approach because the health risk is unproven (claims about the harmful effects of mercury on women and children are exaggerated and misleading), there is no demonstrated technology to meet the limits (particularly if additional emission reductions were required), or raise electric rates as much. The commenters believed emissions trading could help companies avoid potential reliability problems while improving the environment by encouraging earlier reductions through new technology.

Many commenters (OAR-2002-0056-1673, -1955, -2224, -2833, -2844, -2861, -2883 -2897, -2900, -2907, -2918, -3211, -3445, -3478, -3522, -3530, -3537, -3546, -4454, -4891) cited the success of the Acid Rain Program as illustrating the advantages of the cap-and-trade system. One commenter (OAR-2002-0056-2897) agreed that "[t]he challenge in creating an environmental market is often to design the predecessor regulatory system that will create proper incentives to produce the technological developments that are preconditions for a transition to a market." The commenter stated that the Acid Rain Program achieved that success with clear

emission caps, the establishment of allowances that were traded as financial instruments, a national market program, the lack of any restrictions on the instruments, and a program design that rewarded the innovator and the environmental investor.

Another commenter (OAR-2002-0056-2883) stated that as EPA's acid rain program has shown, a well-constructed cap-and-trade program can achieve significant emission reductions with lower cost than other regulatory approaches. The commenter believed a cap-and-trade program provides individual units maximum flexibility to achieve an emissions cap.

Several commenters (OAR-2002-0056-2883, -3530) pointed out it also encourages the development and installation of individual control technologies and rewards early reductions or additional reductions through the use of a banking system. For these reasons, the commenters favored a cap-and-trade approach over a MACT approach for regulating mercury.

One commenter (OAR-2002-0056-2835) contrasted the Acid Rain Program and NO_x SIP Call to command and control type of regulations that would limit compliance flexibility and might impose regulatory constraints that not only unnecessarily increase compliance costs, but also pose real reliability concerns. The commenter believed an emissions trading framework is an effective regulatory mechanism to ensure that reliable power can be delivered to customers while installing the requisite emission controls.

According to another commenter (OAR-2002-0056-3522), especially given the substantial variability in emissions of mercury from plant to plant, the uncertainty about the levels of existing mercury emissions from power plants and the lack of commercially proven technology to control mercury emissions from the commenter's sub--bituminous and western bituminous coal-fired generation, a cap and trade program would be the best option.

One commenter (OAR-2002-0056-4454) submitted the following policy justifications for cap and trade, in addition to the compliance successes and operational flexibilities realized through the Acid Rain Program: (a) additional time needed to manufacture, install and calibrate emission control equipment; and (b) additional time needed to develop accurate continuous monitoring technology, and more time to manufacture, install and calibrate it.

One commenter (OAR-2002-0056-2897) believed that a cap-and-trade approach would be far more effective than a conventional "command and control" regulatory MACT at promoting the development of dedicated maximum achievable control technologies. According to the commenter, as the existing fleet is not equipped with dedicated mercury control technologies, the MACT methodology, which is based on the performance of existing units, cannot promote the development of dedicated control technologies. The commenter stated that, however, a national cap-and-trade approach, which includes limits that decrease with time, would provide incentive for the development of effective and affordable technology. Thus, the commenter encouraged a design feature with decreasing allowances over time to increase the value of the allowances as commodities. The commenter believed this should help to create the market forces to commercialize technology.

One commenter (OAR-2002-0056-2835) believed the power sector is well suited to a cap-and-trade regulatory framework. Given the relatively small number of emissions sources to be regulated, the administrative burdens of the program should be minimal. The commenter also believed a cap-and-trade program for mercury would not thwart the achievement of the Act's goals to protect human health and the environment. One important reason was that mercury is a "global" pollutant for which there does not appear, in most cases, to be a pressing need to require minimum reductions at each and every affected EGU.

One commenter (OAR-2002-0056-3454) stated that past experience with technology development for other pollutants (SO_2, NO_x, and PM) as well as other source categories such as mobile sources, suggests that delaying the regulation of mercury emissions from power plants would serve to delay the development of innovative control technologies. The commenter believed that research and development efforts would be unlikely to be sustained at a vigorous level in the absence of regulatory or other drivers capable of creating a viable market for advanced control technologies. The commenter submitted that larger markets provide more incentives for the development of technologies as well as foster competition between vendors that produces more innovative and cost effective solutions for affected sources.

One commenter (OAR-2002-0056-2819) stated that if EPA decides to pursue trading and banking despite the lack of legal authority, any trading and banking program should be used to supplement rather than supplant other CAA requirements. At a minimum, EPA must adopt an initial set of regulations under section 112. The commenter suggested that any additional regulations adopted under section 111 using trading and banking should allow only for achieving compliance with a cap that is more stringent that the MACT standards.

One commenter (OAR-2002-0056-2181) stated cap and trade programs work best when a clear, enforceable emissions cap is established, based upon the appropriate environmental or public health goal. The cap is then accompanied by an emissions trading system that allows competitive markets–not regulators–to determine the lowest cost method to elicit the reductions necessary to accomplish the goal. The commenter believed trading programs are distorted when they are skewed to favor a particular fuel source, encourage a specific technology choice or protect a particular vintage or business segment. The commenter concluded that such market distortions are merely a subtle way of returning to more traditional command and control regulatory regimes and will reduce the cost-minimizing function of the trading program, hinder progress toward air quality improvements, or both.

Response:

EPA is finalizing a cap-and-trade program under section 111 and is finalizing caps and timing that are integrated with the Clean Air Interstate Rule (CAIR). See final rule preamble for further discussion.

5.1.2 Oppose Cap and Trade

Comment:

Many commenters specifically stated that EPA should abandon the cap-and-trade approach. The commenters believed that while a cap-and-trade program may be effective and appropriate for nontoxic pollutants, it is not permitted by section 112(d) for HAP. Many commenters submitted that cap-and-trade approaches fall short of what is technologically feasible and needed to protect human health and the environment. A trading scheme would allow dirty plants to continue to emit high levels of mercury by purchasing credits from cleaner plants and not installing controls, which would further endanger the health of surrounding communities. with hot spots.

One commenter (OAR-2002-0056-3449) opposed a cap and trade approach for mercury except as a supplement to more stringent MACT standards. The commenter stated mercury emissions remaining after compliance with a cap and trade program would cause unaccpetable adverse health effects; hot spots would remain.

One commenter (OAR-2002-0056-2067) stated that cap and trade is inappropriate because it encourages the development of mercury "hot spots," i.e., the commenter claimed that some individual power plant units might continue to emit mercury under a cap and trade approach, causing localized mercury deposition. The commenter stated that, alternatively, the MACT approach would require the installation of control technology on all power plants and would bring the balance of the industry to the same emissions level as those utilities that have been industry leaders for decades. Similarly, another commenter (OAR-2002-0056-2359) noted that the purpose of standards under section 112 is to raise the control performance of all sources to the level of the top 12 percent. The commenter submitted that trading would be in direct contrast to this purpose as utilities would trade for credits rather than install controls. The commenter believes that all existing units must be required to meet limits. The commenter concluded that allowing trading would invite legal challenges that would further delay MACT promulgation and implementation.

Many Indian tribes and organizations strongly opposed cap and trade due to the deferral of mercury controls, the inadequate level of control, and lack of measures to prevent hot spots. Waters they depend on for fishing are contaminated by mercury deposition from local, regional, and international deposition. In many cases, Indian lands are largely wetlands which are more susceptible to methylmercury formation or otherwise sensitive to mercury contamination due to site-specific factors.

Several Indian tribes (OAR-2002-0056-1327, -2010, -2110, -2118, -2173, -3311, -3549, -3550, -3551) opposed cap and trade because unlike the Federal government, states do not have trust responsibilities for tribes and tribes have no formal role in rulemakings. The commenters believed state-run programs would be inefficient, ineffective, and not in the best interest of health and the environment.

One commenter (OAR-2002-0056-3469) believed the best method for the EPA to reach its goals for SO_2, NO_x and mercury emissions reductions and to prevent penalizing Indian country coal and already clean plants, would be to require all power plants producing more than 50 MW in the nation that are not scrubbed, to install emission control equipment that meets the latest standards. The commenter stated this approach was preferred to cap and trade programs.

One commenter (OAR-2002-0056-2519) noted that during the summer of 2002 EPA initiated the two-year process under the Clean Air Act Advisory Committee's Mercury Working Group, seeking stakeholder input to develop the merury emissions control program. That process considered various technical, policy and legal issues associated with setting the MACT standard. The commenter submitted that at no time during those deliberations was there any suggestion to utilize a cap-and-trade program in lieu of MACT standards. Accordingly, there was no opportunity to fully assess and debate various issues associated with such a mercury emissions control approach.

One commenter (OAR-2002-0056-3449) submitted that emission trading is not appropriate for HAP and that the current Acid Rain and NO_x SIP call programs are not good models for advancing trading of criteria pollutants or mercury. The commenter claimed some components have proven problematic. Unrestricted banking has been shown to be inappropriate in the SO_2 trading program; the 2000 cap has yet to be met because of banking. The commenter stated that if it is met anytime soon, it will be because of NSR settlements. The commenter believes banking would also prevent achievement of the 15 tpy mercury cap in 2018 for at least a decade.

Several commenters (OAR-2002-0056-2364, -3435) claimed the mercury emission reductions under the section 111 cap-and-trade approach would be too little too late. One commenter (OAR-2002-0056-2364) found this proposal inadequate because: the cap is too high and EPA provided no justification for it (installation of MACT controls should reduce emissions to about 7.5 tpy), the 2030 compliance date for reaching the cap is too long and ignored attainment dates for the 8-hr ozone and $PM_{2.5}$ rules (the commenter recommends a compliance date between 2012 to 2015), and would not protect areas from localized hot spots. The second commenter (OAR-2002-0056-3435) stated it is inappropriate and a dangerous precedent to treat a listed HAP outside the 112 framework.

Several commenters (OAR-2002-0056-2695, -2814, -4190) submitted questions regarding the cap and trade program: (1) How does EPA intend to provide accountability for the system? (2) What are the potential risks to endangered species and other flora and fauna? (3) How will the risk assessment and cost benefit analysis include tribal values, unique exposure pathways, and consumption levels? (4) Given that mercury is transported over large areas and has local impacts, is it environmentally safe to trade allowances? (5) What rule provisions will prevent plants from buying allowances to increase emissions regardless of the affects on surrounding communities? (6) How will EPA (or how could tribes) measure the reduction of human and environmental exposure? (7) What is the potential for creating hot spots? (8) How will the program protect Indian resources used in traditional, cultural, and subsistence practices?

Several commenters (OAR-2002-0056-2871, -2889) contended that comparisons to the acid rain trading program are inappropriate because of the nature of the pollutants. The commenters stated that the acid rain program focuses on pollutants with welfare effects while mercury is a neurotoxin with serious health effects. Similarly, one commenter (OAR-2002-0056-2243) stated that although NO_x and SO_2 trading programs are a success, the commenter did not support this approach with mercury. According to the commenter, trading ounces of mercury did not appear to be a reasonable approach. The commenter was concerned with the ability to accurately monitor and tabulate emissions. Also, the commenter stated that a trading program for hazardous air pollutants could not be viewed as a preferred control strategy.

One commenter (OAR-2002-0056-3561), a Maine Congressman attached testimony from Maine officials and residents opposing the proposal in a state public hearing. [Note: attached testimony is not in docket].

One commenter (OAR-2002-0056-2836) consisting of US Senators and Congressmen contended that EPA's weak proposal under CAA section 111 would not result in major reductions of mercury for at least 10 years beyond the time frame required for MACT standards. The commenter claimed this would result in more pollution and health risk and would fail to encourage new technology. The commenter noted that EPA's own modeling showed that Clear Skies legislation, which calls for essentially the same mercury reduction on the same schedule as the section 111 approach, would exempt almost 200 of the oldest and dirtiest coal-fired plants from installing advanced pollution controls for decades. It also showed that the section 111 approach would achieve at best a 58 percent reduction in mercury emissions by 2020, well below the 69 percent goal for 2018. The commenter stated that in addition, the Energy Information Administration predicts that the plants would reduce mercury emissions by only 40 percent by 2025. The commenter stated in addition, the section 111 cap and trade approach would fail to protect local populations from hot spots. The commenter submitted that EPA has instead committed to evaluate the health risks that remain without committing to prevent or eliminate those risks.

One commenter (OAR-2002-0056-2951) believed in the recent debate over the desirability of a "Cap and Trade" system for utility mercury, too much concentration has been placed on the desirability of the Trading; yet the key to maximizing social welfare is dramatically reducing and accelerating the proposed Cap. The commenter stated that it may be comforting for economists to recognize that, given that MACT law is eventually followed and the utility emission limits are set at some real semblance of "the average of the best-performing 12 percent," the loss of the efficiencies of trading will not be that great. According to the commenter, the primary reason for this is simply that if the average required mercury reduction is truly in the neighborhood of 80 percent to 90 percent, then there will not be much over compliance from which to draw tradable allowances. The commenter stated that mercury is, indeed, an air toxic and common sense dictates that if it can be limited cost-effectively to a high degree–and it can–then it deserves to be. The commenter believed emission allowance trading is just not designed for accelerated compliance with 80+percent reduction requirements. The commenter added that further, because of the nature of the likely control methods to be predominately used in complying with strict emissions limits–lower-mercury coals and sorbent

injection into existing particulate collectors–the ability to trade emission allowances would yield only minimal economic gains. The commenter stated that coal-mercury rationalization and sorbent injection are not capital-intensive control methods: their costs vary directly with their use. The commenter noted that economic benefits of trading are maximized when great disparities in marginal compliance costs among units exist. The commenter believed this is simply not turning out to be the case with utility mercury. The commenter stated that even in the high-cost compliance cases, like units with hot-side ESPs or those that sell their fly ash for concrete, technological advances are reducing the compliance costs considerably. (See the Sorbent Technologies' presentations on the e-Docket at OAR-2002-0056-1461 and OAR-2002-0056-1463.) The commenter believed that efficiency analogies with the SO_2-allowance-trading experience are simply not there.

One commenter (OAR-2002-0056-3398) opposed interstate trading of mercury emissions because of the potential for hot spots.

Response:

EPA is finalizing a cap-and-trade program under section 111 and is finalizing caps and timing that are integrated with the CAIR. See final rule preamble for further discussion.

5.2 LEGAL AUTHORITY FOR CAP AND TRADE

Commenter:

One commenter (OAR-2002-0056-3531) stated that by implementing the program nationally and requiring EPA's CAMD group to oversee the implementation, the rules will not add any regulatory or cost burden to the states.

One commenter (OAR-2002-0056-3478) stated that a cap and trade program would have to be set up in an equitable manner. The commenter also stated that it would be imperative that the allowance allocation system be transparent and provide certainty for the units complying with the cap and trade program. For this reason, the commenter did not support the cap and trade approach under section 111. The commenter believed that this method would allow individual states to determine whether, among other things, to 1) let its electric generators participate in a national cap and trade program; 2) allocate all, some, or none of its budgeted allowances to the generators; 3) auction the allowances back to the generators; 4) withhold allowances from a given generator or 5) let its generators buy and sell allowances out of state. According to the commenter, in addition to being a major enforcement and oversight challenge for EPA, the resulting patchwork of conflicting programs could create even greater challenges to electric generators, endanger the stability of the grid, increase costs to consumers, and ultimately delay reductions in utility mercury emissions.

Several commenters (OAR-2002-0056-2046, -2247, -2871, -2887, -2889, -4139) feared a cap-and-trade program under section 111(d) would require states to develop and submit a SIP-like plan for approval to regulate existing facilities which would result in a patchwork of

varying regulations and limits. The commenters claimed the section 111 approach would be time-consuming, duplicative, and inconsistent. One commenter (OAR-2002-0056-4139) stated also, there are no assurances that EPA would consider depostion from an upwind state when reviewing the "SIP-like" control requirements. Therefore, the section 111(d) approach would not protect the commenter from upwind states.

Several commenters (OAR-2002-0056-1763, -4177) asserted EPA's section 111 proposal is unworkable because EPA can only promulgate regulations that establish a procedure for states to follow in establishing NSPS for existing sources. This could result in states developing their own mercury plans rather than following a consistent approach. This does not comport with the national multi-pollutant framework. One commenter (OAR-2002-0056-4177) added that it would be an administrative nightmare and many states would opt out making it useless. This approach would prolong implementation, create uncertainty, and make an uneven playing field.

Several commenters (OAR-2002-0056-2414, -3351) stated that the CAA section 111 cap-and-trade alternative is not an option for toxic air pollutants. One commenter (OAR-2002-0056-2414) submitted that section 111 is designed only to address emissions of non-hazardous air pollutants from new sources. In addition, the original intent of the Act demands across the board reductions. By definition, a trading program does not require reductions from all sources. The second commenter (OAR-2002-0056-3351) stated that section 111 was designed to address criteria pollutants like SO_2 and NO_x.

One commenter (OAR-2002-0056-2521) stated that many stakeholders have charged, and the Administration has itself acknowledged, that there are substantial questions as to the legality of the EPA regulatory proposal to regulate mercury under a cap-and-trade system, whether under section 111 or 112 of the Clean Air Act. According to the commenter, the mere fact that these and other legal questions were being raised, regardless of how they are eventually resolved, meant substantial delay and uncertainty in terms of putting stable standards in place. The commenter was concerned that if the courts resolve the legal questions contrary to EPA's position, the Agency would have to propose a stricter standard-but only after a period of continued uncertainty.

Response:

EPA is finalizing a cap-and-trade program under section 111 and is finalizing caps and timing that are integrated with the CAIR. See final rule preamble for further discussion.

Comment:

Several commenters (OAR-2002-0056-1673, -2172, -2224, -2899, -2922, -2929, -3537) believed that EPA has the legal authority under CAA section 111(d) to establish a cap-and-trade program to control mercury emissions from utility units.

One commenter (OAR-2002-0056-3537) submitted that EPA's proposal to revise its "necessary" finding made in December 2000 is supportable under the administrative record. The

commenter believed EPA's justification that another viable statutory mechanism exists to adequately address mercury (and nickel) emissions from coal (and oil-fired) Utility Units–CAA §111–is legally justifiable. The commenter also believed EPA's interpretation of §112(n)(1)(A)–that just because it is appropriate to regulate Utility Units, EPA is not compelled to regulate them under §112 if other authorities in the CAA exist to adequately address health hazards that occur as a result of HAP emissions–is a reasonable interpretation of the term "necessary" in §112(n)(1)(A). The commenter stated that if EPA withdraws its determination that regulation under §112 is necessary, then EPA should not be required to go through a formal de-listing procedure to remove Utility Units from the §112(c) list. The commenter submitted EPA's interpretation of the phrase best system of control, coupled with the definition of standard performance in §111(a) to allow a cap and trade program is reasonable in the context of establishing NSPS for mercury pursuant to CAA §111. The commenter believed EPA's analysis of the use of §§111(b) and (d) to establish NSPS for new and existing coal-fired Utility Units for mercury emissions is reasonable in the context of establishing a cap and trade program pursuant to §111. The commenter stated in summary, although it may not be the best approach, especially from an efficiency standpoint, a cap-and-trade program established pursuant to §111 is a viable and appropriate statutory mechanism by which to regulate mercury emissions from new and existing coal-fired Utility Units. However, should EPA proceed forward to establish a cap and trade program pursuant to §111, the commenter believed that the general approach outlined by the commenter in section 3.24 (in OAR-2002-0056-3537) would be a much improved version of EPA's proposed cap and trade system in the currently proposed Mercury Rule.

Similarly, another commenter (OAR-2002-0056-2899) believed that CAA section 112(n)(1)(A) provides EPA with broad authority to craft regulations to address any public health concerns it identifies. The commenter stated that section 112(n)(1)(A) does not require EPA to regulate under §112(c) and (d); instead, the provision provides generally that EPA shall regulate under this section if the Administrator finds that regulation is appropriate and necessary. The commenter stated the most consistent reading of §112(n)(1)(A) is that Congress intended EPA to consider a variety of control options to address whatever heath concerns were identified in the Report to Congress and then to promulgate rules based on the best of those options. The commenter added that the limited legislative history of §112(n)(1)(A) supports a broad grant of authority. The commenter stated this legislative history indicates that EPA has broad discretion to establish regulatory standards, should it find such standards necessary to protect public health.

One commenter (OAR-2002-0056-2224) stated that it should be emphasized that CAA section 111(d)(1) itself does not independently mandate that standards of performance for existing sources impose a source-specific requirement for continuous emission reduction. According to the commenter, thus, a state plan incorporating a standard of performance that employs a cap-and-trade mechanism would not conflict with the statutory requirements of section 111(d)(1). Moreover, the commenter believed that the emissions cap and allowance-holding requirement in EPA's proposed section 111(d) trading program arguably would have the effect of imposing a "continuous emissions reduction" requirement on affected electric generating units (EGUs). According to the commenter, specifically, the proposed section 111(d)(1) cap-and-trade program would establish a permanent cap on mercury emissions and

require affected sources to hold allowances that correspond to the level of mercury emissions from those sources at all times.

Response:

EPA is finalizing a cap-and-trade program under section 111 and is finalizing caps and timing that are integrated with the CAIR. See final rule preamble for further discussion.

Comment:

Many commenters (OAR-2002-0056-2108, -2219. -2695, -2823, -2871, -2887, -2889, -3205, -3457, -4117) did not believe that mercury emissions trading is legal under either section 111 or 112(d) of the Clean Air Act.

The public interest group comprehensive comments (OAR-2002-0056-3459) stated that the proposed cap and trade program is not permitted under section 111. The commenter claimed judicial decisions limit pollution trading under the CAA and do not authorize EPA's proposed approach as follow: (1) EPA's attempt to permit even limited emission trading under CAA section 111 has been rejected by the U.S. Court of Appeals (ASARCO v. EPA, 578 F.2d 319 (DC Cir. 1978). For new and modified sources, EPA may allow some form of intra-source trading to avoid the application of PSD permit requirements but the offsetting changes must be within the same source (Alabama Power Co. v. Costle, 636 F.2d 323, DC Cir 1980). And, while Congress added provisions for trading programs in several parts of the CAA as part of the 1990 amendments, it did not do so for section 111. (2) The legislative history of CAA section 111 indicates a Congressional desire for uniform national standards, not a tradeable system of allowances. Congress's manifested intent that every individual source meet the same standard is fundamentally inconsistent with a cap-and-trade program in which some plants would be able to emit more than would be allowed by a technology-based standard because they have traded with other plants. And, nothing in the legislative history suggests that the "best system" be interpreted so broadly. To the contrary, the best system is consistently understood to be the best system that an individual plant could implement and the legislative history of the 1990 amendments reaffirms that the best system applies to individual plants and not to a novel regulatory system. While Congress reverted to the 1970 definition of "standard of performance" to provide plants more flexibility, this clearly was intended to apply within the constraint of a command and control system.

One commenter (OAR-2002-0056-2823) comprised of eleven State Attorney Generals stated that mercury emissions trading is illegal and inappropriate under either section 111 or 112(d) Act because mercury emissions may be deposited in close proximity to power plants resulting in "hot spots." The commenter submitted the following supporting information: (1) EPA's own report recognizes that buying allowances cannot address a hot spot if the cap does not require sufficient reductions to minimize or prevent local impacts. EPA's plan to evaluate the protectiveness of the program after 2018 provides no assurance that hot spots will be adequately dealt with. (2) EPA's proposed trading program does not address mercury "hot spots." It is well documented that mercury must be controlled at a local level and a national cap

and trade approach by itself will not address local issues. Recent studies show considerable hot spots and that up to 95 percent of the mecury can be of the reactive form that is deposited locally (Florida Everglades, New Hampshire data). EPA has also ignored it's own policy statements that trading may be inappropriate for highly toxic pollutants like mercury. (3) The trading program as proposed does not include adequate restrictions, such as temporal restrictions on the use of allowances. EPA has ignored its own policy guidance on how to design a cap and trade program so as to address localized hot spots. Also, EPA's provision for unlimited flexibility, such as the proposed safety valve, undermines any potential for a trading program to address hot spots. (4) Other regulatory standards and level of required reductions are inadequate to address localized impact. EPA fails to recognize that the acid rain program has certain "backstops" that are not in the mercury proposal. (See pages 55-61).

One commenter (OAR-2002-0056-2108) noted that CAA sections 111(b) and 112(d) require a performance standard or an emissions standard. The trading program does not require a source to achieve any particular level of control.

Another commenter (OAR-2002-0056-2219) pointed out that according to EPA guidance (Environmental Incentive Performance), trading programs must be able to quantify the pollutant reduction. The commenter claimed it is not possible to quantify mercury emissions because baseline levels are not well established. Also, some ecosystems are more sensitive to mercury deposition and accumulation than others, making the need for accurate measurement imperative. The commenter believed a trading program should not be allowed because it conflicts with EPA guidance. One commenter (OAR-2002-0056-2887) also strongly opposed the removal of coal and oil-fired units from the list of source categories in CAA section 112(c). The commenter felt this action would be entirely inconsistent with the air toxics program since these units comprise one of the largest sources of HAP in the country. One commenter (OAR-2002-0056-3205) stated that if EPA rescinds its December 2000 finding that it is necessary and appropriate to regulate HAP from coal fired utility units, the requirement for case-by-case MACT determinations for new units required by section 112(g) would no longer apply. The commenter would be adversely affected because the state (Montana) would likely rescind its MACT limit for the proposed new Roundup power plant . The commenter concluded that although EPA has proposed a cap-and-trade program, if it rescinds the December 2000 regulatory finding, the commenter agreed with Environmental Defense that the program is unlawful.

Response:

EPA is finalizing a cap-and-trade program under section 111 and is finalizing caps and timing that are integrated with the CAIR. See final rule preamble for further discussion.

Comment:

Several commenters (OAR-2002-0056-2897, -3556, -3565) believed a nationwide cap-and-trade program under CAA section 112 would create a more efficient regulatory structure than a similar program under CAA section 111. One commenter (OAR-2002-0056-2897) stated the 111 approach recognizes the inherent cost-effectiveness of emission trading compared to

traditional command-and-control regulation; however, the commenter stated the practical problems with section 111 are evident. In the commenter's view, the 111(d) approach, while well intended would not be a market-based approach and would result in extended delays in achieving its intended purpose. The commenter believed the 111(d) program inherently withdraws the incentive offered to the early innovator and the early investor. The commenter added that under 111, it will take years to have any understanding of the final approved plans, and the careful investor will withhold investment until it can better understand which states are in, which states are out, and which states will reward investment. The commenter stated this would only result in delays in commercializing of remediation technology. The commenter added that lack of a national allowance system would only create further investment delays. According to the commenter, it appeared likely the 111(d) approach already lacks state support. For example, the commenter noted the Northeast OTC "does not support a cap-and-trade for Mercury (Hg) beyond a facility's borders. The OTC supports a bubble concept for mercury at a given facility." The commenter also noted that eleven of the 12 OTC states voted to oppose any cap-and-trade program for mercury, with Virginia abstaining. The commenter concluded that if the purpose of this rulemaking is to get the international ball rolling then the 112(n)(1)(a) approach offers the most likely manner of expediting commercialized remediation technology.

A second commenter (OAR-2002-0056-3556) believed that the Clean Air Act provides EPA with broad discretion as to how it chooses to regulate EGUs for HAPs emissions. The commenter's preference and recommendation was that the Agency do so under the provisions of CAA section 112(n)(1)(A). The commenter believed that this section would provide EPA with the discretion it requires, yet would create a program with a uniform format that is national in scope. The commenter strongly believed that a Federally operated, national emissions trading program is essential if this effort is to achieve the desired emissions reduction in the quickest and most economical manner.

Response:

EPA is finalizing a cap-and-trade program under section 111 and is finalizing caps and timing that are integrated with the CAIR. See final rule preamble for further discussion.

5.3 NATIONWIDE CAP AND COMPLIANCE DATES

5.3.1 Timing of Compliance Dates

Comment:

Several commenters (OAR-2002-0056-1625, -1673, -1768, -1814, -2117) expressed concern over the proposed mercury rule and the Interstate Air Quality Rule (IAQR). One commenter (OAR-2002-0056-1625) stated that a potential timing issue would be the possible requirement of mercury reductions to take place in 2008, 2 years before the SO_x and NO_x reductions of the Interstate Air Quality proposal. The commenter submitted that EPA must harmonize the mercury compliance dates with the deadlines for the SO_x and NO_x reductions. For an effective multi-pollutant control strategy that best mirrors the advantages of Clear Skies,

another commenter (OAR-2002-0056-1673) stated that EPA must coordinate and harmonize the mercury rule and IAQR as much as possible. In setting reduction targets and compliance deadlines for individual pollutants, several commenters (OAR-2002-0056-1673, -1768) stated that EPA should fully consider the co-benefits that pollution controls such as SO_2 scrubbers and SCR controls will have for reduction of other pollutants. The commenters believed that aligning reduction targets and compliance deadlines would allow companies to address SO_2, NO_x, and mercury in one integrated step, rather than two. The commenters submitted this would promote the efficient utilization of resources and better ensure timely compliance. The commenters added therefore, it is critical for the Phase I compliance dates under both rules to be set for 2010. The commenters believed that, as in Clear Skies, the Phase I mercury reduction targets should be set at the co-benefit level resulting from Phase I of the IAQR. Failure to align these deadlines and reduction targets would not only increase compliance costs substantially, but could actually impede the early installation of the most effective control technologies.

Another commenter (OAR-2002-0056-1814) stated that EPA has taken the innovative approach of proposing the IAQR rules at the same time as the mercury rules. The commenter also stated that this is important because controls that would be required under the IAQR will achieve significant reductions in mercury emissions, through co-benefits of the control devices. The commenter believed setting the Phase I target at the level of co-benefits of SO_2 and NO_x control is appropriate considering the low concentrations emitted from power plants and the difficulty of achieving mercury reductions.

Response:

EPA is finalizing a cap-and-trade program under section 111 and is finalizing caps and timing that are integrated with the CAIR. See final rule preamble for further discussion.

Comment:

One commenter (OAR-2002-0056-3431) stated that the small and medium-sized units that risk shutdown if unit-specific controls were mandated are not expendable; they provide a valuable electric service reliability benefit to the national grid. The commenter added that specifically, they provide operating reserves, load balancing capability, regulation, and voltage support. The commenter believed based on the current demands on the grid, it is critical this reliability support not be ignored, particularly when EPA can achieve the same or better aggregate reduction of mercury emissions utilizing a mandated cap and trade program. Similarly, one commenter (OAR-2002-0056-2431) argued that an unreasonably accelerated compliance schedule for a MACT standard could lead to reliability problems and outages for equipment installation when this rule and the IAQR rule are considered. The commenter also noted that new control technologies are 2-3 years from completing demonstration.

Response:

EPA is finalizing a cap-and-trade program under section 111 and is finalizing caps and timing that are integrated with the CAIR. See final rule preamble for further discussion.

Comment:

Many commenters (OAR-2002-0056-1768, -2042, -2123, -2224, -2833, -2844, -2906, -2907, -3443, -3537) stated that the cap-and-trade approach to mercury control should be adopted in conjunction with the proposed interstate air quality rules. One commenter (OAR-2002-0056-2906) supported an approach of imposing mercury emission reductions to a level commensurate with co-benefits achieved through the SO_2 and NO_x emissions reductions of the CAIR. The commenter noted however, those reductions must be made in an equitable fashion between coal ranks, recognizing the inherent difference in trace metal concentration, and the differing ability of SO_2 and NO_x emission control systems to remove mercury from those different coal ranks, with consideration of chlorine content impact. The commenter believed this approach would help to mitigate the costs of compliance, which would be borne by all electricity consumers.

Similarly, one commenter (OAR-2002-0056-1768) stated that the final rule should, to the greatest extent possible, rely on SO_2 and NO_x control technologies to meet mercury reduction obligations. One commenter (OAR-2002-0056-2224) stated EPA's proposed cap-and-trade option would be the best way to ensure the mercury co-benefits reductions can be realized by achieving significant, cost-effective reductions for all three pollutants at the same time. The commenter stated that working within a rigorous MACT-regulatory context instead of a cap-and-trade framework would afford EPA and industry much less flexibility in terms of timing of compliance. The commenter noted that the statute allows, at most, three years for meeting the MACT emissions limits. The commenter also pointed out that although a compliance extension would be possible, CAA section 112(i)(3)(B) provides only a one-year extension in cases where "such addition period is necessary." The commenter added that furthermore, the CAA only authorizes longer extensions in time through a "Presidential Exemption." According to the commenter, this statutory provision has never been used and does not authorize an extension of the compliance deadline unless the following two criteria have been met: 1) that "'the technology to implement such standard is not available," and 2) that a compliance extension "is in national security interests of the United States." According to the commenter, it was far from clear whether both criteria could ever be satisfied, which only exacerbates the lack of regulatory certainty for the power sector.

Response:

EPA is finalizing a cap-and-trade program under section 111 and is finalizing caps and timing that are integrated with the CAIR. See final rule preamble for further discussion.

Comment: One commenter (OAR-2002-0056-1768) supported the concept of multi-emissions regulation, but was concerned over the economic and technological feasibility of the basic time frames and levels of reductions under the trading options. The commenter encouraged the EPA to incorporate provisions to lengthen the time frames and levels should achievement not be possible in the proposed rules.

Response:

EPA is finalizing a cap-and-trade program under section 111and is finalizing caps and timing that is integrated with the Clean Air Interstate Rule. See final rule preamble for further discussion.

Comment:

Several commenters (OAR-2002-0056-2160, -2375, -2818, -2833, -2835, -2844, -2867, -2899, -3531) stated that the compliance dates for emission controls for mercury should be coordinated with the compliance dates for controls for sulfur dioxide and nitrogen oxides under the proposed Interstate Air Quality Rule. The commenters submitted that if EPA harmonizes the mercury rule deadline with the IAQR Phase I deadline, sources will be able to coordinate their planning and avoid wasteful investments in pollution controls and maximize the mercury removal co-benefits from SO_2 and NO_x controls. One commenter (OAR-2002-0056-2818) pointed out that given EPA's determination that the coordinated regulation of mercury, sulfur dioxide and nitrogen oxides allows mercury reductions to be achieved in a cost effective manner due to the co-benefit of mercury removal to be derived form controls for sulfur dioxide and nitrogen oxides, it would be reasonable and in the national interest to have the mercury compliance deadlines match those under the proposed Interstate Air Quality Rule.

Several commenters (OAR-2002-0056-2915, -4132) expressed concern that the deadlines for having emissions controls installed and operational in the mercury rule and in the CAIR may not be the same. One commenter (OAR-2002-0056-2915) stated that after EPA lengthens the compliance deadlines in the mercury rule compared to the proposed compliance deadlines, EPA would need to establish CAIR compliance deadlines such that they are synchronized with such lengthened compliance dates in the mercury rule to allow electric generators to develop cost-effective planning strategies that allow them to take advantage of co-benefit mercury emissions reductions that can be achieved through SO_2 and NO_x control technologies. The commenters claimed that failure to synchronize these deadlines could affect electric rates and reliability.

Several commenters (OAR-2002-0056-2830, -2850, -3443) stated that the first phase of the CAIR and the first phase compliance date for mercury under a cap and trade scheme should be delayed. Several commenters (OAR-2002-0056-2830, -2850) noted that 2010 was established as the date for first phase compliance for SO_2 and NO_x under the Clear Skies legislation. Two years have elapsed since Clear Skies was proposed. The commenters recommended that the first phase of the CAIR and the first phase compliance date for mercury under a cap and trade scheme should be delayed 2 years, i.e., from 2010 to 2012. One commenter (OAR-2002-0056-3443) stated that in their comments on the CAIR, they noted the likely scheduling problems associated with fabricating the control equipment and obtaining requisite permits for waste disposal. For these reasons, the commenter recommended that the CAIR schedules be adjusted to make the first phase effective in 2011 and the second phase in 2016. Consistent with these earlier comments, the commenter would expect the timing of Phase I under both rules be linked such that if the CAIR schedule is adjusted, the mercury schedule

would follow suit. The commenter stated that synergy between the two rules will facilitate the reduction of emissions of multiple pollutants (SO_2, NO_x, and Hg) in a cost-effective manner. If Phase I of the CAIR is delayed, the commenter believed the onset of the mercury program should also be delayed and sources be allowed to earn early reduction credits in the interim prior to the onset. The commenter submitted that this is an environmentally preferable approach since early reductions would be achieved while still ensuring that the two rules are implemented in tandem.

One commenter (OAR-2002-0056-2521) stated that the Clean Air Planning Act proposes a 24-ton cap in 2009 on mercury emissions from the industry sector, and the Northeast States for Coordinated Air Use Management (NESCAUM) equates the commenter's recommendation to the Working Group with a 13.1-ton cap in 2008. In light of its view that these targets are achievable, the commenter anticipated no need for a one-year extension (from 2008 to 2009) for the implementation of the 34-ton cap that EPA proposed.

Response:

EPA is finalizing a cap-and-trade program under section 111 and is finalizing caps and timing that are integrated with the CAIR. See final rule preamble for further discussion.

Comment:

Several commenters (OAR-2002-0056-2833, -3440, -3530) stated that in the final rule, EPA must not tighten the standards or compliance deadlines set forth in the proposed rule. The commenters submitted that the reduction requirements in the proposed rule are extremely aggressive and will be very difficult for many companies to meet. One commenter (OAR-2002-0056-3440) noted the first phase is proposed to take effect in 2010, leaving companies only 5 years to make decisions on the type of control and to set about procuring contracts for labor and materials. The commenter stated this is particularly concerning for the Texas lignite units, the majority of which are fitted with sulfur dioxide controls already and have no demonstrated control technology available for mercury removal. Given that national applicability of this rule, Texas utilities will not be the only ones involved in this process. The commenter was concerned about the effect on labor and material costs to the electric generators as a result of such a shortened timeframe. All of the commenters believed it is important for the deadlines and emission reduction levels to be tied to the practicability of hundreds of units to acquire labor, materials and permits and control technologies (many at the same time) in order to install controls without sacrificing reliable and low-cost electric generation. Several commenters (2833, 3530) believed EPA should provide for time extensions for companies to comply with the standards if they can demonstrate reasonable concern for grid reliability or security problems, technological infeasibility or financial hardship. One commenter (OAR-2002-0056-2833) stated that EPA should determine whether and when reliable, cost-effective control technologies to capture mercury emissions will be fully developed and tested or made commercially available on a wide-enough scale to reduce mercury emissions.

Many commenters (OAR-2002-0056-2067, -2332, -2375, -2441, -2551, -2899, -2915, -2929, -3510, -3531) expressed concern that the proposed compliance schedule might not allow sufficient time to install the control technologies that will be needed to meet the CAIR and mercury program mandates, especially for reductions required by 2010. Several commenters (OAR-2002-0056-2899, -2915) observed that EPA predicts, based on the CAIR proposal, that almost 80 GW of capacity would install either flue gas desulfurization or selective catalytic reduction to reduce SO_2 and NO_x, respectively, between 2005 and 2010. The commenters also noted that EPA assumes that companies will not begin construction activities until 2007 when the states and EPA finalize requirements, leaving just parts of three years (2007, 2008 and 2009) to install control technologies on hundreds of generating units.

These commenters (OAR-2002-0056-2899, -2915) stated simultaneous installations of controls under the CAIR and mercury programs at hundreds of units would stress labor, materials, and state and local permitting agencies. The commenters explained that the process for a single installation would involve a complicated engineering review, negotiation of contracts with vendors, obtaining permits from local and state authorities, and engaging contractors, materials and machinery at the site for construction. The commenters added that all this would be done in an environment of limited availability of expert labor, especially for boilermakers; in addition to a shortage of boilermakers, there could be a shortage of electricians, pipefitters and ironworkers. The commenters also stated that installations take the plant off-line for weeks, and such outages must be coordinated within the company and throughout the region with other types of outages in order to avoid stretching the generation capacity too thin and exposing the grid to upset and potential blackouts.

One commenter (OAR-2002-0056-2899) noted EPA assumes that the CAIR installations can be done hundreds of times concurrently, in less time than electric companies believe possible. According to the commenter, installing one scrubber requires approximately 48-54 months: about 12 months to select the appropriate technology and establish design criteria; 12-18 months for engineering and design; and 24-30 months (depending on weather) for construction and startup. The commenter added that the permitting process can take years, especially for a new landfill. The commenter submitted that these time constraints would most likely be longer with hundreds of affected sources installing control equipment within the same time frame. The commenter added that the demand for labor for complying with the industrial boiler MACT program will further strain the labor supply.

The commenter (OAR-2002-0056-2899) noted that the Utility Air Regulatory Group (UARG) concluded that the probability is high that the boilermaker labor pool will not be sufficient to install all of the necessary control technology by 2010; that is, 1) EPA has optimistically assumed that all of the boilermakers who would be available for work on electric utility environmental retrofit projects would be fully utilized, 40 hours a week for 50 weeks a year, and 2) alternative electricity demand growth projections of the Energy Information Administration (EIA) would require 15 percent greater retrofits.

One commenter (OAR-2002-0056-2661) stated that rural electric cooperatives generally have systems that are smaller with fewer units than the average utility and, therefore, would have

an even more difficult time competing for limited resources and equipment. Also, the commenter noted that the time needed by cooperatives to obtain financing from the Department of Agriculture Rural Utility Services would not support a three or four-year compliance schedule, which is key to providing safe, affordable, and reliable energy needs of our member-owners. The commenter believed installation of any mercury control requirements must coincide and be integrated with existing and new SO_2, NO_x and particulate control measures required over the next decade.

One commenter (OAR-2002-0056-2067) stated that financing arrangements can pose significant obstacles to a relatively short compliance period, especially for public power entities.

One commenter (OAR-2002-0056-2441) stated mercury-specific controls do not exist yet on a commercially available basis and new regulations must provide adequate time for the commercial development of control technologies capable of meeting emission reduction targets. Similarly several commenters OAR-2002-0056-2915, -3510) submitted that demonstrated control technology does not exist to reduce mercury emissions from Gulf Coast lignite-fired power plants. Commenter OAR-2002-0056-2915 noted that the majority of Gulf Coast lignite-fired EGUs are fitted with SO_2 controls already.

One commenter (OAR-2002-0056-2929) stated that in its CAIR comments, the commenter suggested that EPA take into consideration the difficulty for some companies to meet the 2010 targets and provide a regulatory fix to this almost inevitable problem. The commenter submitted the same regulatory considerations should be provided for a mercury cap-and-trade program that relies on supposed CAIR co-benefits.

One commenter (OAR-2002-0056-2422) favored the longer time frames for compliance that are available under cap-and-trade alternatives. The commenter believed that with the absence of commercially demonstrated technologies for controlling mercury emissions from coal-fired power plants, a longer compliance timetable such as 2018 would provide needed time for the testing, demonstration and commercialization of Activated Carbon Injection and similarly promising mercury control technologies.

Response:

EPA is finalizing a cap-and-trade program under section 111 and is finalizing caps and timing that are integrated with the CAIR. See final rule preamble for further discussion. EPA believes its timeframe is appropriately addresses the time needed to install controls and the concerns about financing controls. See final rule preamble for further discussion.

Comment:

Many commenters stated that the compliance time frame for the cap and trade program (2018) is too long. The commenters noted that banking provisions extend the compliance date for 14 years or more. This would be counter to Clean Air Act requirements and also is at odds with settlement agreement. These commenters supported an earlier time frame using the existing

provisions of the Clean Air Act for extensions under section 112(i) to allow time to install controls or longer, using the Presidential exemption provision. One commenter (OAR-2002-0056-2064) added that DOE is expected to have cost effective mercury control available by 2010. EPA's mercury rule should at least be consistent with that timing. One commenter, OAR-2002-0056-2094, also believed reductions should occur by 2010 and the Clean Air Act has provisions to accomodate this timeframe. Several commenters (OAR-2002-0056-2094, -2108) also explained that compliance is needed by 2010 for states to have TMDLs in place by 2015 to address impaired waters as required under the CWA. Another commenter suggested that mercury controls should be in place at the same time as control for other pollutants.

One commenter (OAR-2002-0056-2247) asserted the final mercury cap must be in place sooner than 2018. The commenter concluded that the availability of labor is not a real constraint as suggested by EPA in its rationale for the proposed effective dates of the caps. The commenter noted that EPA's own analysis shows that recent power plant activity due to the NO_x SIP call has increased the labor supply and other EPA analyses show that there is sufficient boilermaker labor to meet the IAQR needs. This analysis did not take into account any increase in number of boilermakers as a result of new demand. The commenter stated that the effective date for mercury should be the same as the IAQR- an interim cap in 2010 and a final cap in 2015. This would not change the costs for a significant portion of the units and would force control technology development at a slightly aggressive date. The commenter believed an earlier date would not seriously compromise a plant's ability to plan and execute mercury reduction requirements. An earlier deadline would also help to make technology available sooner to developing countries like China. The commenter submitted this would better address concerns about mercury from global sources if we could offer cost effective methods and deploy it sooner.

Response:

EPA is finalizing a cap-and-trade program under section 111 and is finalizing caps and timing that are integrated with the CAIR. See final rule preamble for further discussion. EPA believes its timeframe is appropriately addresses the time needed to install controls and the concerns about financing controls. See final rule preamble for further discussion.

Comment:

Several commenters (OAR-2002-0056-1673, -2243, -2830, -2850, -2879, -2922, -3463, -3469, -3539, -3548) supported EPA's efforts to coordinate the mercury emissions reduction program with the sulfur dioxide and nitrogen oxides reductions proposed under the IAQR rule. One commenter (OAR-2002-0056-2850) noted that keeping the timing of mercury rule control requirements compatible with the IAQR should assure that cobenefits from SO_2 and NO_x cap and trade methodology are not sub-optimized due to accelerated mercury control timing requirements. Another commenter stated that a multi-phased and balanced national cap and trade program would take advantage of the co-benefits derived from implementation of the IAQR while providing time for the full development and installation of mercury-specific control equipment.

Several commenters (OAR-2002-0056-2862, -3463) stated that compliance deadlines for UMRR should be set to match the deadlines that are established for compliance with the phases of the IAQR cap-and-trade program. One commenter (OAR-2002-0056-2826) noted EPA's proposed IAQR requires compliance with Phase I SO_2 and NO, emission reductions by 2010 and compliance with Phase II SO_2 and NO, emission reductions by 2015. EPA's MACT option specifies a 2008 compliance deadline, while EPA's Cap and Trade options under section 112 or section 111 specify a 2010 Phase I compliance deadline. The section 111 and 112 Cap and Trade Options also include a Phase II compliance date of 2018. One commenter (OAR-2002-0056-3436) noted that these deadlines should be adjusted if the IAQR timeline is adjusted. However, the commenter recommended that, if anything, the deadlines be pushed further back into the future in order to allow time for the development of mercury control and monitoring technologies for emissions from coal-fired power plants. Similarly another commenter (OAR-2002-0056-3469) recommended that the compliance time frames proposed under the UMRR and IAQR be consistent and adjusted to reflect the two years which have passed since Clear Skies was first proposed. The commenter stated that this would set the first phase compliance date for a cap and trade program at 2012. An additional commenter (OAR-2002-0056-3548) also strongly supported EPA's efforts to coordinate the schedules of the proposed IAQR and mercury rules, as many of the controls expected to be needed for the IAQR may also address emissions of mercury.

One commenter (OAR-2002-0056-1673) submitted that to ensure a broad range of compliance options, the cap-and-trade program under the UMRR and IAQR should be consistent with previous trading rules.

One commenter (OAR-2002-0056-2243) stated that in a cap and trade environment, addressing mercury, NO_x, and SO_2 simultaneously will insure that adequate allowances will be available for either existing unit expansion and/or new project construction.

Several commenters (OAR-2002-0056-1889, -2323, -2346) stated that the cap-and-trade program can be coordinated with the timing of SO_2 and NO_x controls proposed under the IAQR and should be a nation-wide program. The commenters also stated that this coordination will enable power generators to take full advantage of the way SCR and scrubber systems can help reduce mercury emissions while also reducing SO_2 and NO_x. Several of the commenters (OAR-2002-0056-1889, -2323) believed this allowance allocation system should mirror the methodology used in the successful acid rain control program.

One commenter (OAR-2002-0056-2346) supported a multi-pollutant, market-based approach and believed that with some enhancements, the IAQR could be a vital, cost-effective air regulatory program for the United States. The commenter stated that the proposed cap-and-trade program is superior to the MACT program because 1) Cap-and-trade would reduce mercury emissions by almost 70 percent from 2001 levels, achieving the MACT goal by 2010 and capping emissions at 15 tons in 2018. The MACT would only reduce these emissions from coal fired power plants by 29 percent from 2001 levels by 2007; 2) There is no commercially available mercury control technology for coal fired power plants. Therefore, it would be impossible for the industry to comply with the MACT timetable of 2007; and 3) The

cap-and-trade program can be coordinated with the timing of SO_2 and NO_x controls proposed under the IAQR and should be a nation-wide program.

One commenter (OAR-2002-0056-3830) has publicly supported the Clear Skies Initiative and supports a coordinated approach to utility emission reductions that would provide a "systems" approach, thus reducing uncertainty and cost. The commenter believed EPA's intent to coordinate the development of the proposed Mercury and CAIR rules would provide a more cost-effective approach to developing emission control systems. The commenter supported, in concept, the cap and trade as it would allow time for the development of potentially cost-effective control technologies and would offer a more reasonable implementation schedule.

One commenter (OAR-2002-0056-2911) has been an advocate for a multi-pollutant approach to address the need for the electric generation industry to make further reductions in the emissions of SO_2, NO_x and mercury. The commenter believed that a comprehensive program would produce those reductions faster and more cost-effectively than the traditional regulatory approach. The commenter stated that EPA is to be commended for its efforts to craft a regulatory framework to implement such a program. However, the commenter believed that a multi-pollutant approach would be best implemented through legislation. The commenter stated that EPA faces many obstacles as it moves to implement a multi-pollutant program for EGUs, within the existing framework of the Clean Air Act–particularly with respect to keeping the schedules of the CAIR and the proposed mercury rule in synch.

One commenter (OAR-2002-0056-2850) stated that it is crucial that any regulatory requirements result in a level playing field for all affected sources. The commenter added that compliance timeframes must be flexible and harmonized with the Clean Air Interstate Rule (CAIR) to ensure continued reliability, to feasibly allow capital investment, and to recognize that there are no currently available commercial technologies designed exclusively for mercury control from electric utilities.

Response:

EPA is finalizing a cap-and-trade program under section 111 and is finalizing caps and timing that are integrated with the CAIR. See final rule preamble for further discussion.

5.3.2 Level of Reduction Required by Caps

Comment:

One commenter (OAR-2002-0056-1768) stated that deeper mercury reductions beyond the co-benefits associated with SO_2 and NO_x caps should be based on the progress of technology development and a clear demonstration of a health benefit. Also, emerging scientific research suggested to the commenter that reducing mercury emissions from the U.S. power generating sector does little to reduce the amount of mercury deposition in the United States or the levels of methyl-mercury in fish. The commenter submitted that forcing all power plants to install expensive anti-pollution devices would not necessarily ensure reductions in methylated mercury

levels in local environments. The commenter asserted that the final rules must address the scientific uncertainties and complexities of mercury pollution in addition to providing flexibility and weighing known costs against unknown benefits of regulation.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. See preamble for further rationale for the 15 ton cap.

Comment: One commenter (OAR-2002-0056-1611) submitted that the NC Clean Smokestacks Act will reduce emissions far more than the President's proposal and should be used as the national model rule.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. See preamble for further discussion.

Comment:

Several commenters (OAR-2002-0056-2660, -2838, -2871, -2887, -2889, -3437, -3449, -4117) submitted that the proposed mercury standards under the cap and trade options are too weak and the implementation time frame is too long.

One commenter (OAR-2002-0056-3449) stated that trading only makes sense if the caps are set at well below the standards that otherwise would have been set. Commenter OAR-2002-0056-3449 believed a defensible MACT standard should result in emissions in the 5-10 tpy range by a set deadline, which would be a much greater reduction than the 15 tpy actual in 2018 that EPA proposed.

One commenter (OAR-2002-0056-3437) was concerned that EPA is using projections to estimate future emissions and reductions. The proposed Phase II cap would be 15 tons in 2018 based on a percentage reduction rather than an estimate of possible emissions based on possibly faulty projections. The commenter submitted that EPA should determine a reasonable percentage reduction for both Phase I and Phase II and should not use unknow co-benefits for establishing a budget. Several commenters (OAR-2002-0056-2871, -2889, -2660, -2838, -2887, -4117) also pointed out that the Phase I cap (34 ton/yr cap in 2010) does not require any mercury specific controls beyond the incidental reductions expected from the IAQR. The commenters added, while the proposal cites a 15 ton/yr final cap in 2018, the impacts analysis shows the final cap would not be achieved. The commenters noted that EPA acknowledged that emissions could be as high as 22 tons when banking, trading, and resultant delays are considered. One Commenter (OAR-2002-0056-2887) also pointed out that the section 111 proposal is totally dependent on the IAQR. The commenters asked, what if the IAQR is not finalized or promulgation is delayed? The commenters believed it is questionable that the interim cap would

be enforceable. Another commenter (OAR-2002-0056-2660) added that that IAQR does not extend to the 15 western states so it is possible there would be no mercury reduction ever from any western power plants and that the limits for subbituminous coal are so lax that there probably will not be any mercury reduction within the state either. The commenter asserted the proposed limits would not achieve the needed reductions.

One commenter (OAR-2002-0056-2887) and several states also opposed the section 111 proposal because the deadlines are extremely protracted given the seriousness of mercury pollution and its toxicity. The commenters pointed out that the settlement agreement calls for final HAP standards by March 2005, with compliance by December 2007 (with extensions if justified). The proposal postpones compliance until 2018 and beyond due to banking and trading provisions. The commenters submitted this delay is inappropriate, irresponsible, and unacceptable. It is also counter to CAA requirements and the settlement agreement. The commenters believed feasible controls are certainly available now. The commenters pointed out that for example, Massachusetts rules require 85 percent control by 2008 and 95 percent in 2012.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. See preamble for further rationale.

Comment:

One commenter (OAR-2002-0056-4177) opposed the cap and trade approach but stated that if EPA proceeds with it, the cap should be about 7 tons/yr (same as an appropriate MACT standard), with a final compliance date as close as possible to the 2007 date required by section 112 and the court settlement agreement.

Several commenters (OAR-2002-0056-0501, -2569) specifically stated that a more ambitious cap and trade program might be effective in reducing emissions with minimal costs to industry. One commenter (OAR-2002-0056-2569) recommended increasing the phase I reduction to 20 tons by 2009 and the phase 2 reduction to 45 tons by 2015. The commenter believed these reductions ccould be made easily on those plants with configurations compatible with existing control technology.

One commenter (OAR-2002-0056-3444) submitted that the calculation of achievable caps in 2010 and 2018 would require operating data of Utility Units during the baseline period.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. See preamble for further rationale.

Comment:

Several commenters (OAR-2002-0056-2519, -3543) submitted that the extent of co-benefits reductions of SO_2 and NO_x controls is unknown under the cap and trade program. One commenter (OAR-2002-0056-2519) noted that the EPA proposal solicits comments on what level should be selected for Phase I mercury emissions cap. The proposal states that EPA expects mercury emission reductions under the Phase I cap would result via "co-benefits" (resulting from actions designed to achieve SO_2 and NO_x emission controls by retrofitting SO_2 scrubbers and SCR) in areas covered by the proposed Interstate Air Quality Rule (IAQR region) of 29 Eastern sates and D.C. EPA suggested setting a Phase I cap of around 34 tons, the level anticipated via co-benefits from sources located throughout the country. The commenter stated however, similar estimates by WEST Associates and the U. S. Department of Energy range from 36.5 tons to 42 tons. The commenter believed that with the 1999 baseline mercury emissions of 48 tons, setting a Phase I cap "too high" will create a credibility problem while picking a cap that is "too low" may not be achievable with co-benefits alone.

The commenter submitted it is not possible to accurately predict how much mercury emission reductions will occur via co-benefits in the IAQR region. First, because the proposed mercury cap-and-trade program does not impose any geographic limitation on mercury trading, there is no assurance which plants will reduce emissions, and which will rely on buying credits from the market. For example, some of the reductions would occur at plants located outside the IAQR region, and hence, the reductions from the IAQR region would be less than estimated. Second, many, if not most sources in the IAQR region could shift their fuel (where the infrastructure exists) from current use of bituminous coal to sub-bituminous coal (not only for mercury reduction purposes but also to reduce SO_2 emission reductions for achieving $PM_{2.5}$ standards). The commenter added it is well known that mercury reductions expected via co-benefits from sub-bituminous coal are much lower than in the case of bituminous coal. Therefore, not knowing which plants might switch fuel or which plants will elect to buy credits, there is no way anyone can accurately predict what level of mercury emission reductions would occur via co-benefits. The commenter stated thus, it is not possible to set a Phase I mercury emissions cap that relies exclusively on co-benefits in the IAQR region.

The commenter also stated that finally, EPA has not provided state-by-state mercury budgets for Phase I starting in 2010, primarily due to the fact that EPA has not specified a Phase I cap. It was unclear to the commenter whether EPA expects mercury emission reductions during Phase I (via co-benefits) from sources located outside the IAQR region. The commenter noted that as sources outside the IAQR region are not expected to install scrubbers and SCR to attain $PM_{2.5}$ standards, no mercury emission reductions via co-benefits can be expected to occur at sources outside the IAQR region in the near term. Accordingly, if the Phase I cap is set beyond the co-benefits level, sources outside the IAQR region will have to either install scrubbers and SCR or other mercury specific control measures sooner than their counterparts would have to do in the IAQR region. The commenter points out that such a scenario could result in unfair competitive advantages for sources in the IAQR region. Accordingly, there is considerable uncertainty on the compliance obligations under Phase I for sources located in regions outside the IAQR region.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. See final preamble for further rationale. EPA is establishing a firm cap for the first phase and provided State and Tribal emissions budgets. For further discussion of state emision budgets see final rule preamble (section IV.C.4) and Technical Support Document for CAMR Notice of Final Rulemaking, State and Tribal Emissions Budgets, EPA, March 2005.

Comment:

Many commenters (OAR-2002-0056-1608, -1768, -1859, -1969, -2224, -2375, -2818, -2830, -2833, -2835, -2850, -2861, -2895, -2898, -2907, -2918, -3327, -3444, -3463, -3469, -3530, -3546, -4891) supported setting the phase I mercury cap at a level that's commensurate with the co-benefit reductions anticipated to be achieved through implementation of SO_2 and NO_x reductions under the transport rule.

Several commenters (OAR-2002-0056-1969, -2830, -3463, -3469) asserted that tying the proposed 2010 mercury reductions to co-benefits will allow reliable data on the mercury content of lignite and mercury emissions to be collected, co-benefits to be evaluated, and will provide additional time to research and develop effective control and monitoring technology. Thus, the commenters recommended against setting a hard cap and recommended that the cap simply be the level which co-benefits can deliver.

Commenters OAR-2002-0056-3463 and OAR-2002-0056-3469 stated that if a soft cap approach is adopted, banking of allowances should not be permitted in Phase I. One commenter (OAR-2002-0056-3463) added that a non-numeric cap such as this is also appropriate because mercury removal as a co-benefit of SO_2 and NO_x control technology is unproven. According to the commenter, EPA has acknowledged that currently-available control equipment cannot achieve consistent levels of mercury removal in the elemental phase. The commenter stated that since current control equipment cannot effectively remove mercury in the elemental phase, EPA should not put a cap on emissions levels from lignite-fired units. According to the commenter, with no known control method for elemental mercury, a specific limit on lignite emissions levels would force lignite operations to buy allowances or switch fuel–either of which would effectively put the Texas Gulf Coast Lignite industry out of business.

One commenter (OAR-2002-0056-2224) stated that EPA does not propose a specific level of mercury control for Phase I of the cap-and-trade program under either option. The commenter noted that rather, EPA proposes to set the mercury emissions cap at the level that can be achieved through the installation of controls that are necessary to meet the Phase I emission caps in the proposed IAQR. The commenter asserted that setting the mercury missions cap at this level fully realizes the mercury "co-benefit" reductions associated with the controls required under the IAQR. According to the commenter, a more stringent emissions cap—that is one that does not correspond to the controls for NO_x and SO_2–would present significant compliance and reliability concerns to the power industry given that control technologies for mercury are not yet

commercially available. The commenter was still evaluating the appropriate level for setting a "co-benefit" emission cap. The commenter stated that EPA should be guided by best available data from technical analyses developed by DOE and other entities that suggest that a 34-ton cap level may be overly optimistic. The commenter noted that when setting the Phase I mercury cap, EPA should consider that the IAQR only covers the Eastern United States.

One commenter (OAR-2002-0056-2918) stated that the amount of mercury emissions reduction that will be achieved as co-benefits has a particularly significant impact in the western U.S. According to the commenter, two-thirds of the western units are already scrubbed to remove SO_2. The commenter added however, that scrubber technology is not as effective in mercury capture in the western U.S. because coals burned there emit a relatively higher proportion of elemental mercury compared to oxidized mercury due to their lower chlorine content.

In an analysis included in the docket (OAR-2002-0056-1912), commenter OAR-2002-0056-2918 examined EPA's NATEMIS files and the applicable data sets from EPA's 1999 Information Collection Request (ICR) supporting this rulemaking, and estimated the maximum co-benefits achievable by the application of pollution controls to coal-fired units to meet proposed CSA reduction targets for SO_2 and NO_x. The commenter submitted that this analysis indicates a co-benefits cap of 36.5 tons under the best of circumstances. The commenter believed that in all likelihood, co-benefit mercury emission reductions will be less, and the Phase I cap should be set at a higher level. Consequently, if the 2010 cap is to truly reflect co-benefits, then it was the commenter's view that it should be at minimum of 36.5 tons. One commenter (OAR-2002-0056-3522) proposed that the Phase I cap be set at no less than 36.5 tons as commenter OAR-2002-0056-2918 recommended, and that this cap be accompanied by an effective safety valve. This commenter added that others, such as the Department of Energy, estimated even higher emissions, depending, for example, on whether one assumes that the use of SCR reduces emissions of mercury along with emissions of NO_x.

One commenter (OAR-2002-0056-2900) also stated that EPA has suggested that the appropriate mercury cap for Phase I is 34 tons and noted that Department of Energy and West Associates data suggest that a higher level likely is more realistic. First, the commenter did not believe that EPA had taken into account many units that recently have switched or are in the process of switching to sub-bituminous, low sulfur coal. The commenter stated that as a result of such fuel switching, the reductions EPA has anticipated due to the co-benefits of SO_2 and NO_x controls and based on the proposed MACT standards would not be as great. Second, the commenter believed EPA needs to re-evaluate the overall expected mercury co-benefits of compliance with Phase I of the CAIR.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. EPA is establishing a firm cap of 38 tons based on EPA's modeling of projected CAIR Hg co-benefits. See final preamble for further rationale.

Comment:

Several commenters (OAR-2002-0056-2375, -2903) suggested to avoid basing the Phase I cap on as-yet-unknown Interstate Air Quality Rule (IAQR) co-benefits, EPA should promulgate a final rule stating that the Phase I cap will be at least 34 tpy and no greater than 38 tpy. The commenters continued that based on emissions data that will be available to EPA in 2008, EPA should determine in 2009 what the Phase I cap should be in 2010. The commenters concluded that if EPA determines that co-benefits have resulted in emissions (i) below 34 tpy, EPA will set a 34 tpy Phase I cap; (ii) between 34 tpy and 38 tpy, EPA will set the cap at the specific level; (iii) greater than 38 tpy, EPA will set a 38 tpy Phase I cap.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. EPA is establishing a firm cap of 38 tons based on EPA's modeling of projected CAIR Hg co-benefits. EPA believes it is important to establish the cap level in the final rulemaking to provide affected sources with certainty and time for compliance planning. See final preamble for further rationale.

Comment:

Similarly one commenter (OAR-2002-0056-3443) recommended the imposition of a Phase I cap of 34 tons per year if the cap and trade program allows for early reduction credits starting in 2008. The commenter noted that early reduction incentives would offer facilities the opportunity to minimize compliance risks and the ability to deliver low-cost, reliable electrical power by accumulating a small buffer of allowances prior to the Phase I start date. Equally important, early reductions would be environmentally beneficial since they would help reduce mercury emissions prior to the Phase I deadline. Alternatively, in the absence of early reduction incentives, the commenter recommended that the Phase I cap be established at the higher end of the CAIR emission levels, i.e., at 38 tons, to account for variability in mercury emissions data. The commenter noted that these recommendations for a Phase I cap were based on the use of heat input adjustment multipliers proposed by EPA (1:1.25:3.0). The commenter believed any further adjustment to these multipliers should be accompanied by a commensurate adjustment of the cap.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. EPA is establishing a firm cap of 38 tons based on EPA's modeling of projected CAIR Hg co-benefits. See final preamble for further rationale. As discussed in comment responses below, section 5.8.3, EPA is not including early reduction credits for Hg in the final rulemaking.

Comment:

Several commenters (OAR-2002-0056-1768, -2833, -3530) stated that many groups are calling for a more stringent mercury cap than the level of reductions achieved through "co-benefits" of SO_2 and NO_x reductions on a faster timetable, under which many plants would be forced to invest over a very short time period in expensive technologies that may not be fully proven for every application nor achieve desired results. The commenters believe that many generators may choose not to "gamble" with their ratepayers' or investors' dollars and instead choose to prematurely retire existing coal-fired capacity, thereby exacerbating utility demand for natural gas.

One commenter (OAR-2002-0056-2835) agreed with EPA that it is unrealistic to establish a mercury cap based on the reductions possibly achievable through activated carbon injection (ACI) and other such breakthrough technologies (e.g., chemical systems to enhance mercury removal efficiencies for wet scrubbers). The commenter believed that these technologies have not been adequately demonstrated on full-scale power plants and thus do not currently provide a reliable means to achieve mercury reductions below the levels achievable through SO_2 scrubbers and selective catalytic reduction (SCR) systems for NO_x. For these reasons, the commenter supported EPA setting the Phase I mercury cap at levels that can be achieved through installation of such conventional SO_2 and NO_x control technologies. The commenter submitted that under this approach, the emissions cap would match actual projected mercury emissions instead of hypothetical best mercury performance through unproven mercury control technologies that are not yet demonstrated. The commenter believes this approach is consistent with the requirement in CAA section 111(d) that the standard of performance be based on the best system of emission reduction that has been adequately demonstrated. The commenter also noted that when setting the Phase I mercury cap, EPA needs to address that the transport rule only covers the eastern states and the very minimal co-benefit mercury reductions achievable in the west, even if the transport rule is expanded to the entire continental United States. Moreover, the commenter also recommended that the Phase I cap for mercury reflect the use of banked SO_2 and NO_x allowances to meet Phase I of the transport rule.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. EPA is establishing a firm cap of 38 tons based on EPA's modeling of projected CAIR Hg co-benefits. See final preamble for further rationale.

Commenter:

One commenter (OAR-2002-0056-2861) believed that any regulation of mercury emissions from coal-fired power plants that goes beyond the level of co-benefit reductions would be premature. The commenter submitted that mercury-specific control technologies to achieve reliable reductions in mercury emissions from power plants are not commercially available, as EPA acknowledged in its proposal. The commenter noted that while EPA's response to that

problem is to develop a cap based on "co-benefits" of SO_2 and NO_x controls beginning in 2010, the problem remains that establishing any hard cap in 2010 would be inconsistent with a "co-benefits" philosophy. The commenter claimed the performance of SO_2 and NO_x controls relative to their ability to consistently and reliably remove mercury is still largely unknown. The commenter asserted therefore, since it is impossible at this time to predict with reasonable certainty either the SO_2 and NO_x controls that will be installed to comply with EPA's CAIR or their effectiveness at removing mercury, any attempt by EPA to set a hard emissions cap in 2010 at any level and call it a co-benefit is nothing more than a guess, with the utility industry and its customers holding the risk. If EPA guessed on the low side and set a cap below what co-benefits would actually turn out to be as a result of CAIR implementation (the 34 ton number that has surfaced as a possible level that EPA may be considering for a 2010 co-benefits cap by all accounts is well below even the most aggressive estimate of what co-benefits might turn out to be in 2010), the industry would be faced with having to install controls specifically to remove mercury, controls that by 2010 EPA acknowledges will not be ready for deployment in support of a regulatory requirement. The commenter stated that promulgating such a regulatory requirement would seem an archetype of arbitrary and capricious agency action.

Commenter OAR-2002-0056-2861 stated that utilities and others are investigating ways to make the performance of SO_2 and NO_x controls more predictable and consistent, but at this time there is no way to know with any certainty how much reduction can be reliably achieved at a particular unit over an extended period of time. The commenter asserted not only would this uncertainty create problems for assuring compliance at a given unit, but also it would have serious impacts on the ability to create a robust and effective emissions trading market. The commenter submitted utilities will be reluctant to sell allowances if they are unsure whether they can actually achieve the reductions necessary to free up excess allowances.

In light of concerns over technology availability and performance and the likely adverse impacts on the efficient operation of a cap and trade program, commenter 2861 recommended that no hard cap on mercury emissions be set for either 2010 or 2018 at this time. The commenter suggested instead, any final rule should specify that reductions in mercury emissions will be measured to quantify the co-benefit performance of controls that will be required under separate federal or state programs including the CAIR, Regional Haze, or state requirements such as North Carolina's Clean Smokestacks Act. The commenter stated that to assure that co-benefit mercury reductions are maximized, EPA could specify that each unit equipped with a wet or dry SO_2 flue gas desulfurization (FGD) system would develop an operational plan to quantify mercury reductions and to develop operational parameters to optimize mercury removal performance to the extent practical, without adverse impact on boiler performance or SO_2 and NO_x removal. The commenter added the rule could also specify that the question of whether to require reductions beyond co-benefits would be revisited by 2013 after several years of operating data are collected and analyzed. These data would provide better information about the actual co-benefit level of reductions that can be achieved and will inform an assessment of whether further reductions beyond co-benefits are warranted. The commenter believed this approach would provide several years to gather data on mercury speciation, mercury removal associated with FGD and SCR systems, and advances in mercury control technology for both elemental and non-elemental mercury.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. EPA is establishing a firm cap of 38 tons based on EPA's modeling of projected CAIR Hg co-benefits. EPA believes it is important to establish the cap level in the final rulemaking to provide affected sources with certainty and time for compliance planning. See final preamble for further rationale.

Comment: One commenter (OAR-2002-0056-2895) noted that the exact level of mercury reduction that will be realized as a result of the IAQR is uncertain and hence the level of a co-benefit cap is not known. The commenter submitted that estimates of a co-benefit cap range from 34 to 42 tons. The commenter suggested that one possible approach to establishing a co-benefits cap would be to implement required mercury monitoring (source testing or monitoring) in the beginning of 2008. By mid 2009, the EPA would have more mercury emission data that could be used to estimate a more informed level for a co-benefit cap. The commenter stated the December 2004 final rule can establish a co-benefit level range with the final number being established in mid 2009.

One commenter (OAR-2002-0056-2907) supported a Phase I program based on a true co-benefits approach, which must take into account the fact that it is more difficult to remove elemental mercury from sub-bituminous and lignite coals than it is to remove oxidized mercury from bituminous coal. The commenter noted there is considerable uncertainty regarding the appropriate co-benefits level. Unless EPA can establish the co-benefits cap with certainty, the commenter encouraged the Agency to consider alternatives to a hard 2010 cap on mercury emissions. The commenter's alternatives included (1) deferring a 2010 cap as proposed by EEl; or (2) creating another mechanism to provide industry with adequate relief in the event actual mercury emissions exceed the projected co-benefits emissions level.

One commenter (OAR-2002-0056-3543) stated EPA's rationale for setting Phase I mercury cap at a level that can be achieved through FGD and SCR was inconsistent with the preamble rationale which stated that uncertainty exists in the level of reduction that may be achieved through FGD and SCR on different boiler types burning different ranks of coal.

One commenter (OAR-2002-0056-2430) stated EPA's proposal discussed mercury reductions in 2010 as a co-benefit of the controls required by the IAQR. However, no method for quantifying the mercury reduction was discussed, making it impossible to evaluate expected 2010 reductions under the trading program with 2010 under the MACT proposal.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. EPA is establishing a firm cap of 38 tons based on EPA's modeling of projected CAIR Hg co-benefits. EPA believes it is important to establish the cap level in the final rulemaking to provide affected sources with certainty and time for compliance planning. See final preamble for further rationale.

Comment:

Several commenters (OAR-2002-0056-2521, -2634, -3543) recommended setting a Phase I hard cap. One commenter (OAR-2002-0056-2521) noted that EPA's current proposal includes the following: 1) depending on which of the proposed approaches the Agency adopts, a 34-ton limit or cap on mercury emissions in 2008 to 2010 (a 29 percent reduction from 1999 levels), and a 15-ton cap in 2018 (a 69 percent reduction), and 2) no limit on trading. The commenter then noted that these are the corresponding provisions of the Clean Air Planning Act: 1) a 24-ton cap on mercury emissions in 2009 (a 50 percent reduction from 1999 levels) and a 10-ton cap in 2013 (a 79 percent reduction), and 2) trading of mercury allowances after imposition of a reduction requirement on each facility (of 50 percent in 2009, and 70 percent in 2013, calculated with reference to the quantity of mercury in the coal).

The commenter also stated that during the course of the Working Group's proceedings, the commenter made specific recommendations (letter to Mr. John Paul, co-chair of the Working Group, dated March 28, 2003) regarding subcategories of coal-fired units and emission rates for each subcategory. (According to the commenter, they noted in their March 28 submission that they supported a combined standard that allows the opportunity to meet either a specified emission rate or control efficiency; however, they included only emission rate recommendations at that time in light of the fact that the IPM model-which EPA had intended to use to model the stakeholder recommendations cannot be run with control efficiencies.)

The commenter stated that although their recommendations were rate-based and they did not translate those recommendations into total mass emissions from the industry sector, the Northeast States for Coordinated Air Use Management (NESCAUM) has since done an analysis that translates the recommendations of all of the stakeholder groups that participated in the Working Group into tons of emissions from the industry. According to NESCAUM, the commenter's rate-based recommendations equate to total industry emissions of 13.1 tons of mercury per year, with an implementation date of 2008. Although the commenter was not advocating MACT standards that equate to a highly specific industry-sector tonnage limit, they adopted that calculation for the purposes of having a common metric with which to compare the proposed EPA, Clean Air Planning Act, and commenter's approaches to limiting mercury emissions.

One commenter (OAR-2002-0056-3543) recommended strengthening Phase I by establishing a hard cap at a level designed to eliminate most of the ionic mercury emissions from affected units.

One commenter (OAR-2002-0056-2634) stated that if EPA ultimately decides to establish a numerical cap for 2010 as well as 2018, the commenter supported the position being proposed in WEST's comments, whereas the 2010 cap would be set at 36.5 tons with enhanced safety valves available in 2010 and 2018.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. EPA is establishing a firm cap of 38 tons based on EPA's modeling of projected CAIR Hg co-benefits. EPA believes it is important to establish the cap level in the final rulemaking to provide affected sources with certainty and time for compliance planning. See final preamble for further rationale.

Comment: One commenter (OAR-2002-0056-2835) noted that questions have been raised regarding the timing and stringency of the Phase II mercury cap. These questions appear to stem from the concern that the Phase II compliance deadline for mercury (2018) is three years after the Phase II compliance deadline for SO_2 and NO_x (2015) under the transport rule. The commenter acknowledged that this mismatch in compliance deadlines may enable many electric utilities to bank significant amounts of mercury allowances between 2015 and 2018, and these banked allowances may delay achievement of the Phase II mercury cap for many years after 2018. Furthermore, the commenter acknowledged these concerns, if substantiated, may justify the need for adopting an interim cap in 2015 that is more stringent than the co-benefit cap set in 2010. Under this approach, EPA might defer the imposition of a numeric cap in 2010, preclude banking of pre-2015 allowances in most cases, and require electric utilities to monitor mercury emissions during the initial phase of the program (e.g., 2008 to 2014). The commenter submitted that another approach might be to maintain the co-benefit cap in Phase I (2010-2014), but set it at a slightly higher level to address the many uncertainties inherent during the initial compliance period. Generally speaking, these uncertainties relate to the baseline emissions levels for all affected coal-fired utility units and co-benefit mercury levels projected in 2010 as a result of the transport rule. The program would then:

- Establish an interim cap that would apply during the 2015-2017 period. The control level of the interim cap would be set to reflect, in part, the additional co-benefit mercury reductions achieved under Phase II of the transport rule.

- End with final cap of 15 tons in 2018, as initially proposed by EPA under both cap-and-trade options.

One commenter (OAR-2002-0056-2224) was still evaluating the need and appropriateness of setting an interim mercury cap that would be slightly more stringent than the Phase I cap and might be imposed between the Phase I and Phase II compliance deadlines. The commenter was not opposed to the imposition of such an interim cap if additional mercury reductions are appropriate and necessary prior to 2018 and if the timing and reduction levels of the interim cap levels are done correctly.

One commenter (OAR-2002-0056-2725) noted that in setting an interim milestone, EPA should remember that much of the industry will spend significant dollars and resources over the next ten years reducing emissions of SO_2 and NO_x under the Interstate Air Quality Rule (IAQR) or other programs, and these efforts should result in significant mercury reductions. The commenter believed that EPA should ensure that any interim milestone is consistent with the

co-benefits expected from other control systems installed pursuant to the IAQR. The commenter stated that, as with the final milestone, EPA should recognize the mercury emission reductions arising in the West under other regulatory programs such as Regional Haze.

Several commenters (OAR-2002-0056-2850, -2883, -3443, -3478, -4891) supported the establishment of an interim cap of 24 tons of mercury in 2015 when IAQR Phase II controls are in place. Commenter OAR-2002-0056-2850 stated that this is consistent with the utility industry's commitment to ensuring that the 15-ton cap is met in 2018. Commenter OAR-2002-0056-3478 added that establishing a "hard cap" in 2015 would also limit the amount of mercury allowances that could be banked by 2018 and, therefore, attain the final goal of 15 tons earlier. Commenter OAR-2002-0056-3443 stated they can support the establishment of an intermediate cap in 2015 if early reductions can be banked starting in 2008. The commenter believed banking encourages earlier or greater reductions than are required from sources, stimulates the market and provides flexibility in achieving emissions reduction goals. The commenter submitted that these advantages notwithstanding, banking can also result in the use of allowances in a particular year that exceed the state's trading program budget. Thus, an excessive accumulation of banked allowances could result in a situation where actual emissions in 2018 are significantly above the Phase II cap of 15 tons per year. To prevent the accumulation of excess allowances, the commenter could support the establishment of an intermediate mercury cap of 24 tons in 2015 and a onetime discounting (as described in the following comment) in 2018.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. EPA is establishing a firm cap of 38 tons based on EPA's modeling of projected CAIR Hg co-benefits. EPA believes it is important to establish the cap level in the final rulemaking to provide affected sources with certainty and time for compliance planning. See final preamble for further rationale.

Comment:

One commenter (OAR-2002-0056-2898) stated the 2018 cap level is too stringent given today's state of development of mercury control technologies. The commenter believed it is speculative that controls would be advanced to the point of being capable of controlling mercury emissions nation-wide to levels proposed for 2018. The commenter noted control technology for mercury removal is in the developmental stage. The commenter noted further that the proposed 2018 cap of 15 tons would require technologies that can remove elemental mercury. Since, these technologies are not proven at this time, the commenter submitted that EPA should include provisions in the rule to revisit the long-term cap if technology does not develop that will allow regulated sources to meet this cap. The commenter believed the U.S. economical impact must be weighed against any human health and environmental benefit that would result in the additional reductions.

One commenter (OAR-2002-0056-2907) also had concerns with the proposed Phase II cap of 15 tons. This commenter also believed the cap will require significant reductions in mercury that do not appear to be attainable with current technology. The commenter acknowledged there is considerable ongoing research investigating new technologies to reduce mercury emissions and lower the costs of control, the commenter believed it is premature to set a cap based on the presumption that cost effective controls will be available by 2018. For this reason, the commenter supported a robust "safety valve" to ensure that the mercury emissions reductions required by the Phase II cap are achievable. The commenter stated WEST Associates is filing comments containing such a safety valve.

Several commenters (OAR-2002-0056-3463, -3469) challenged the legal basis for EPA's proposed cap of 15 tons starting in 2018. The commenters claimed the proposal is based on unproven mercury control technology with no associated cost estimates. One commenter (OAR-2002-0056-3463) stated that lignite-fired facilities cannot meet this cap limitation with currently available control technology. The commenter stated that EPA cannot use untested technologies to set emissions requirements. The commenter believed insufficient data exists to establish reliable and attainable mercury emissions limit at this time. The commenter urged EPA to postpone setting a cap for Phase II until reliable data is collected, IAQR-related co-benefit emission reductions are evaluated, and control technology for mercury is developed. One commenter (OAR-2002-0056-3469) stated that given the high level of elemental mercury in lignite and the difficulty of capture it poses, lignite will be put at a disadvantage and utilities will have to purchase excessive amounts of allowances, if available, in order to comply. Both commenters recommended that EPA should establish a Phase II cap based upon the following: data resulting from Phase I, sound science, verifiable public health benefits, proven mercury control technologies, coal type differentiation, amount of contribution to global mercury levels, and equitable treatment of lignite in connection with the cap-and-trade program.

One commenter (OAR-2002-0056-2918) stated that in the NPR, EPA proposed a Phase 2 cap of 15 tons, which reflects approximately a 70 percent reduction from current emissions. The commenter noted the NPR indicates that this cap is based on the modeling used to support the CSA. The NPR specifically states that this modeling "suggests that, assuming technologies such as Activated Carbon Injection (ACI) become available, such a cap (15 tons) will create an incentive for certain plants to install these newer technologies." However, the commenter, in the analysis referred to in the discussion concerning the Proposed Phase 1 cap (OAR-2002-0056-1912), calculated the resulting emissions based on the assumption that a total of 875 units–288,874 MW or ~88 pecent of total generation–were retrofitted with ACI. The commenter's analysis indicated that the resulting mercury emissions would be 19 tons, which is 4 tons higher than the proposed Phase II cap. The commenter concluded that consequently, given the Phase 2 cap is based on the underlying assumptions about the availability of ACI as suggested by CSA modeling, the Phase 2 (2018) cap should in fact be 19 tons.

Several commenters (OAR-2002-0056-2835, -3443, -4891) accepted a final 15-ton cap to become effective in 2018. One commenter (OAR-2002-0056-2835) stated that although ambitious, the level of control may be achievable based on the incremental co-benefit reductions expected from Phase II of the transport rule. The commenter believed that in addition, it is

reasonable to expect that additional mercury reductions can be cost-effectively achieved in 2018 through the application of ACI and/or other emerging technologies that are expected to become commercially available for deployment after 2010. To address the issue of excessive accumulation of banked allowances, one commenter (OAR-2002-0056-3443) recommended that allowances could be discounted in 2018 by a preset percentage of the owner's banked allowances. Reducing the banked allowances in 2018 would ensure that actual mercury emissions from the sector as a whole are near the 15 tons per year level during subsequent years. The commenter emphasized that this discounting must be applied one-time only. No further discounting should be applied to allowances earned after 2018 as otherwise the incentives to create banked allowances would be dampened. The commenter believed, therefore, this discounting mechanism should not discourage the overall banking program.

Several commenters (OAR-2002-0056-2364, -3446, -3455) recommended a tighter Phase II cap. Modeling by ICF conducted for one commenter (OAR-2002-0056-3446) found that incremental changes in the timing and stringency of a mercury cap have modest cost implications. The added costs of a Phase II cap at 10 tons in 2015 (instead of 15 tons in 2018) would be about the same as the cost saving for moving the Phase I cap from 26 to 34 tons. The commenter summarized that on a percentage basis, the incremental environmental benefits from a tighter Phase II cap would exceed the incremental costs.

One commenter (OAR-2002-0056-2364) believed that the emission limits which reduce emissions to 34 tons per year are too high and that additional reduction is needed. The commenter recommended reducing emissions to 5 tons/yr and requested an IPM run to determine the optimal time frame for reaching this lower emission level.

One commenter (OAR-2002-0056-3455) believed EPA should consider enhancing the NO_x and SO_2 controls to achieve more mercury reduction. The commenter believed more stringent limits are technologically possible and recommends limits resulting in 85-90 percent. The commenter submitted that even considering the variability in coals, a national mercury emission cap of 5-10 tons per year is achievable. The commenter stated this is consistent with STAPPA/ALAPCO's recommendation to the working group of a standard reducing emissions to less than 7.5 tons per year and with EPA's straw proposal for a 24 ton cap in 2008 and a final cap of 7.5 tons in 2012. The commenter noted that based on control technologies currently in commercial use or proposed in permit applications, states such as Connecticut, Massachusetts, New Jersey, and Wisconsin have or will adopt limits that represent control efficiencies of 80 to 90 percent or more. The commenter stated these levels can be achieved using the controls required for NO_x and SO_2 reductions under the IAQR if the equipment maximizes mercury control. Tuning for optimal mercury removal, absorbent improvements, and other enhancements for multiple emissions control would be effective measures to improve mercury removal.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. See preamble for further rationale for the 15 ton cap.

Comment:

Many commenters (OAR-2002-0056-2634, -2819, -2861, -2867, -2876 -2911, -2922, -2929, -2945, -2948, -3521, -3556, -3565) believed that EPA should modify its cap-and-trade proposal. One commenter (OAR-2002-0056-2819) recommended that the trading/banking program be based on recommendations issued by STAPPA/ALAPCO and OTC. The STAPPA/ALAPCO analysis recommended a 15-20 ton interim cap by 2008 and a 5-10 ton cap by 2013. The OTC recommended a 15 ton interim cap by 2008, a 10 tons maximum cap for 2012, and a 5 ton cap for 2015. The commenter noted that both of these are more stringent and timely than EPA's proposal and would ensure installation of the best controls nationwide.

One commenter (OAR-2002-0056-2945) specifically supported a multi-phase approach to a national cap and trade program as a means of overcoming the multitude of problems associated with the EPA data, the industry's limited experience with mercury control technology, and the need to maintain affordable electricity generation while developing the necessary experience to reduce mercury emissions in the most cost effective manner. The commenter stated that the Bituminous Coal Coalition's proposed multi-phase approach and timetable is superior to any EPA MACT proposal since it ultimately results in a much lower cap (15 tons) than does the MACT proposal

One commenter (OAR-2002-0056-2922) recommended that a mercury cap-and-trade program be implemented in three phases. In Phase 1, there should not be a numeric cap on mercury emissions. Instead, mercury emission reductions would be those resulting from coal-fired power plants' installing new control equipment to comply with the requirements of EPA's proposed Clean Air Interstate Rule (CAIR), assuming that EPA promulgates that rule. Mercury trading would not occur during Phase 1. Mercury allowances would not be issued and banking of mercury allowances would not occur. Coal-fired units would install and certify mercury monitors in 2008 and begin to monitor mercury emissions in 2009. The commenter stated that the main reason a numeric cap should not be established in Phase 1 is because there is no way to predict the level of mercury reductions that will be a result from utilities' efforts to meet the CAIR requirements. The commenter noted that not setting a numeric limit would avoid excess banking of allowances if the cap was set too high, and conversely, compliance problems if the cap was set below the level of mercury reductions actually achieved from complying with the CAIR. Phase 2 would begin in 2015 with a cap of 24 tons of mercury emissions per year. In Phase 2, mercury allowances would be allocated and mercury trading could occur. Allowances should be allocated on the basis of heat input. The commenter suggested heat input multipliers of 1.0 for bituminous units, 1.5 for sub-bituminous units and 3.0 for lignite units. Phase 3 would begin in 2018 with a cap of 15 tons per year.

Several commenters (OAR-2002-0056-2634, -2861, -2867, -2911, -2929, -2948, -3521, -3556, -3565) supported and recommended the three phase approach recommended by commenter OAR-2002-0056-2922. The commenters also cited advantages to this approach. Several commenters (OAR-2002-0056-2911, -3556) stated that beginning in 2008, the industry would begin a comprehensive emissions measurement program for mercury from EGUs. Similarly, commenter OAR-2002-0056-3565 expressed a willingness to perform continuous

monitoring of mercury emissions using Method 324 beginning in 2008. This measurement program would provide EPA, the states, the industry and the public with detailed information regarding the mercury emissions from each coal-fired EGU.

Several commenters (OAR-2002-0056-2911, -3556) submitted that the primary advantages of this proposal are that it acknowledges that there are significant unknowns regarding mercury emissions from EGUs, allows the opportunity to resolve those unknowns, and affords the opportunity for control technology to catch up with the final goals proposed by EPA–primarily through advancements in reducing the emissions of elemental mercury.

One commenter (OAR-2002-0056-3565) stated that, as a practical matter, there is no way to predict what equipment the utilities will install to meet the CAIR requirements. The commenter added that there is currently much uncertainty as to the amount of mercury reduction that can be achieved by SCR and scrubbers. The commenter stated that the limited data from testing mercury on units with SCR and/or scrubbers has been very varied and inconsistent. The commenter further added that there is also some evidence that some ionic mercury reduces to elemental mercury and is reemitted in some scrubbers. One of the commenter's 1999 ICR stack test sites clearly produced data, which indicated such reemissions were occurring. The commenter believed estimating the amount of mercury co-benefits which will occur in year 2010 is just a guess, therefore, the most straightforward approach is to not set a tons limit for Phase I.

One commenter (OAR-2002-0056-2634) stated that the three phase approach provides greater certainty to the utilities as it accurately addresses the true level of "co-benefits" and it provides sufficient time, between 2008 (when monitoring would begin) and 2015 for utilities to plan for installation of mercury specific controls. The commenter added it is also environmentally beneficial in that it would reduce the total mercury emissions between 2010 and 2018, and would result in actual 2018 emissions being very close to 15 tons through reduced banking.

One commenter (OAR-2002-0056-2861) stated that the three phase approach would achieve several objectives: First, it would eliminate the guesswork that would be involved in setting a co-benefit cap in 2010. Second, it would eliminate the potential that the lack of demonstrated mercury specific removal technology, combined with the difficulty in installing all of the SO_2 and NO_x controls that would be required under CAIR by 2010, could make it impossible for the industry either to meet a specific mercury emissions cap in 2010 or to have an effective mercury trading program in 2010. The commenter submitted that while concerns remain that the 2015 and 2018 targets are still ahead of technology development, the approach would provide more time for the technologies that will be needed to reduce emissions beyond co-benefits to be developed, demonstrated and deployed. The commenter concluded that last, the proposal to move the first cap to 2015 would address concerns that have been expressed that too much banking may occur if utilities are allowed to start banking any reductions below their 2010 allocations. The commenter stated a 2015 cap that sets an emissions cap below co-benefits would make it more difficult to bank reductions for the period from 2015 to 2018. However, the commenter recommended that limited banking be allowed prior to 2015 if the utility can demonstrate that controls have been installed to reduce mercury beyond co-benefits, for

example, if a company installs a demonstration technology to specifically remove mercury. The commenter suggested that will promote early reductions and help development of technologies needed to meet both the 2015 and 2018 caps.

One commenter (OAR-2002-0056-2867) applauded EPA's recognition that mercury-specific control technologies will not be commercially ready for application in the 2010 time frame. The commenter noted that several technologies are in various stages of pilot testing, but none have been demonstrated on a commercial scale for any extended periods of time. The commenter stated that those that have pilot-tested have shown a substantial degree of variability. It was anticipated by the commenter that in the post-2010 period and by the 2018 Phase 2 compliance deadline, the performance of existing technologies would be well demonstrated, and innovative mercury-specific technologies would have matured and be ripe for commercial use. The commenter submitted that the commitment to advance mercury control technology for readiness in the future is demonstrated by the pace of industry research activities and demonstration plans. Active commitment of funds by EPRI, DOE, and several utility companies including AEP, further attest to the commitment of the industry to further development and demonstration.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. EPA examined a three-phase approach but conclude its two-phase approach was appropriate. See preamble for further rationale and Chapter 7 of Final CAMR Regulatory Impact Analysis.

Comment:

Commenter OAR-2002-0056-2867 cited the following advantages of the recommended three phase approach:

- Would provide assurances (through the required monitoring programs) that emission reductions are being steadily phased in toward successful achievement of the ultimate 15-ton cap

- Monitoring capabilities and technologies would have attained the needed level of performance improvement to provide consistent demonstrations of compliance and accurate future allowance allocations under the cap-and-trade program.

- Banking would be limited in the earlier phase, thus ensuring that the 2018 emissions would closely track the ultimate 15 Ton cap. The 3-phase plan would achieve greater mercury reductions in the 2010-2018 period compared to EPA's proposed two-phase plan (a cumulative total of 242 Tons of allowances under a 3-phase plan, versus a cumulative total of 272 Tons of allowances under the 2-phase plan as proposed)

- The interim compliance date would more closely approximate the schedule for implementing demonstrated mercury specific newer technologies that would be elemental mercury specific (the predominant form of mercury expected after the co-benefits based reductions that principally remove the ionic form).

Consistent with the 3-phased approach recommended by commenter OAR-2002-0056-2922 as described above, one commenter (OAR-2002-0056-2876) proposed that a phased, national cap and trade program (under section 112 of the CM) be implemented to reduce power plant mercury emissions. The commenter favored a phased approach because it would not be possible to predict with adequate confidence the co-benefit reductions that would be achieved through the industry's actions to meet CAIR requirements. In addition, the commenter believed a phased approach would allow for the time that is required for the commercialization of mercury-specific control technologies that will be needed for future reductions. However, a key distinction between the commenter's proposed alternatives and the 3-phased approach described above is that the commenter did not believe that EPA has data that are sufficient to support setting an interim (2015) cap, or emissions allocation factors at this time. As noted above, EPA should determine emissions allocation factors by coal type and set an interim cap in 2012; this interim cap should become effective in 2015. The commenter stated the cap and associated factors should be based on a co-benefits analysis of the monitoring data collected in the 2008-2012 period, and an assessment of commercial availability and performance characteristics of mercury control technologies for different coal types. The analysis performed during this period would allow for the implementation of an interim cap that would be achievable (and thus would not promote fuel switching - to natural gas, for example), and avoid emissions allocations among coal ranks that would place certain coal ranks at a market disadvantage.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. EPA examined a three-phase approach but conclude its two-phase approach was appropriate. EPA believes it is important to establish the cap levels in the final rulemaking to provide affected sources with certainty and time for compliance planning. See preamble for further rationale and Chapter 7 of Final CAMR Regulatory Impact Analysis.

Comment:

One commenter (OAR-2002-0056-4894) provided a memo that summarized the results of an EPMM model run simulating the impacts of the EEl's proposed alternative Mercury Cap and Trade program (Alt Hg Option). Under this option, there would be no hard mercury cap until 2015. However, early reduction credits could be earned and banked during the period 2010-2014 if mercury emissions were to be consciously reduced through early application of control technology. Phase I of the mercury cap would start in 2015 and be set to 24 tons. Phase II would start in 2018 when the cap is lowered to 15 tons.

The commenter attached the standard summary tables for this case as an Excel file. This memo highlighted the key results, primarily though comparison with results from EPA's proposed Mercury Cap and Trade Rule (Hg Rule), which has a cap of 34 tons starting in 2010, reduced to 15 tons in 2018. The commenter ran both scenarios with identical assumptions except for the timing and level of the mercury caps.

The Alt Hg Option and the Hg Rule results presented by the commenter both were simulated with an assumption that there would be gradual improvement in activated carbon injection (ACI) mercury control technology: a 2.5 percent annual reduction in the current estimate of the variable costs only of ACI-based technology. The summary tables for this specific version of the Hg Rule scenario were also attached to the memo.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. EPA believes it is important to establish a firm cap of 38 tons in 2010 based on EPA's modeling of projected CAIR Hg co-benefits. See final preamble for further rationale. As discussed in comment responses below, section 5.8.3, EPA is not including early reduction credits for Hg in the final rulemaking.

Comment:

Several commenters (OAR-2002-0056-2880, -2889) urged EPA to adopt the mercury cap levels and reduction timeframes in the Multi-Pollutant Strategy Position of the Ozone Transport Commission (January 27, 2004) and STAPPA/ALAPCO's Principles for a Multi-pollutant Strategy for Power Plants (May 7, 2002 with March 12, 2004 analysis of those principles). The OTC calls for stepwise reductions in mercury emissions: 15 tons/yr in 2008, 10 tons/yr in 2012, 5 tons/yr in 2015 and performance standards for individual units by 2012. These reductions are technically and economically feasible in that timeframe.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. See final preamble for further rationale.

Comment:

One commenter (OAR-2002-0056-3546) was generally supportive of the proposed targets and compliance deadlines for reducing mercury proposed under the cap-and-trade options. However, the commenter urged EPA to further examine these targets and deadlines–which are very ambitious–to ensure that the proposed two-phased mercury control program is technically and economically feasible and consistent with the objectives to ensure adequate supplies of reasonably priced power. Moreover, the commenter submitted that given the stringency of the proposed reduction requirements, the adoption of an emissions trading

program is essential to ensure these objectives are realized and that mercury reduction obligations can be achieved at the lowest possible cost.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. See final preamble for further rationale.

Comment:

One commenter (OAR-2002-0056-2359) stated EPA's weak proposals do not provide incentive for advancing mercury removal technology in conjunction with SO_x, NO_x, and PM. The commenter pointed out that DOE is expected to have cost effective mercury control technology available by 2010; EPA's mercury rules should at least be consistent with that timing.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. EPA believes this cap levels and timing encourage technology development. See final preamble for further rationale.

Comment: One commenter (OAR-2002-0056-3210) opposed EPA's rationale in the supplemental notice for 6 years to adequately conduct a commercial demonstration of mercury controls. The commenter claimed EPA is attempting to selectively develop time lines to justify cap and trade. The commenter noted the 6 year time line includes a pre-award period greater than 12 months, each full-scale demonstration taking another 12 months and inflates the operating and reporting timeline by including the time to prepare a report on the project. The commenter believes a realistic time line is 3-4 years, especially in light of all the full scale demonstration projects already completed or underway. The commenter stated the goal of the DOE/NETL Mercury Control Technology Research Program is for technology for bituminous coal to be available by 2005 and lignite and sub-bitumihnous coal by 2007 and advanced mercury controls for all coal types by 2010. Widespread commercial deployment could begin in 2008 for bituminous and 2011 for lignite and sub-bituminous coal.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. EPA believes this cap levels and timing are consistent with its understanding of technology development. See final preamble for further rationale and see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005, in docket.

Comment: Several commenters (OAR-2002-0056-2054, -2422, -2718, -2922, -3198, -3469) recommended that EPA should implement a phased-in approach to the mercury cap-and-trade program that recognizes the differences in available technology solutions between the various fuel subcategories. Several of the commenters (OAR-2002-0056-2054, -2422, -3198) claimed adequate technical data do not exist at this time to provide a reasoned basis for the allocation of allowances among coal types for purposes of an initial reduction in 2010.

One commenter (OAR-2002-0056-2054) believed the mercury data collected as part of EPA's 1999 Information Collection Request (ICR) is inadequate and inherently flawed. The commenter proposed that EPA acknowledge these data problems and implement mercury regulations that are designed to rectify the situation, while maintaining a reasonable level of environmental control over mercury emissions. Several commenters (OAR-2002-0056-2054, -2422) encouraged initial reliance on the "co-benefit" mercury reductions achieved by the sulfur and nitrogen oxides reductions required by EPA's proposed Interstate Air Quality Rule (IAQR). One commenter (OAR-2002-0056-2422) noted that EPA's mercury co-benefit reduction estimates associated with the IAQR are comparable to those resulting from implementation of the agency's MACT proposal. The commenter noted EPA estimates that compliance with the IAQR will result in an overall level of 34 tons of mercury emissions from the electric generating sector in 2010, due to the installation of 49 Gigawatts (GW) of scrubbers and 24 GW of SCR capacity by 2010.

Several commenters (OAR-2002-0056-2054, -2422, -3198) stated EPA should implement a phased approach to the determination of mercury emission allowance allocations under any form of an emissions trading rule. The commenters submitted a phased approach should be designed with the following milestones:

- 2008-Require installation and initial testing and operation of mercury emission monitoring equipment on affected units;

- 2009-11-Collect and analyze monitor data to determine mercury emissions and reductions achieved by IAQR emission reductions in 2010;

- 2012-Determine prospective emission allocations by coal type for an interim 2015 emissions cap, based on results of the 2009-11 co-benefits analysis, and an assessment of the expected future commercial availability and performance characteristics of mercury control technologies for different coal types;

- 2015-Affected plants meet an interim emissions cap determined by EPA in 2012; banking and trading of allowances commences;

- 2018-Final emissions cap of 15 tons is imposed.

Several commenters (OAR-2002-0056-2054, -2422) recognized that the development of mercury-specific control technologies may, or may not, reduce the need for specific emission allowance allocations by coal type at some point in time. The commenters stated the proposed

2009-2011 analysis of the efficacy of co-benefit control reductions, coupled with an assessment of mercury-specific control technologies, would facilitate a determination of the appropriateness of coal-specific emission allowance allocations to meet an interim 2015 and a final 2018 cap.

Under the commenters' (OAR-2002-0056-2054, -2422, -3198) phased approach, no mercury allowances would be assigned until 2015, for purposes of meeting an interim cap, and no banking or trading of allowances could occur prior to that date. One commenter (OAR-2002-0056-2244) strongly opposed use of the agency's proposed MACT floor values for any allocation of mercury emission allowances. The commenter asserted these floor values were not statistically defensible, and were inappropriate for any regulatory purpose. One commenter (OAR-2002-0056-2054) believed that with this proposal, the total mercury emissions would decrease and be equal to or less than the emission levels under the currently proposed regulatory alternatives. The commenter stated in addition, the additional data collection would insure a just and verifiable regulatory program based on sound science. The commenter also stated that finally, the limited time for banking allowances (3 years) would insure that the maximum mercury reductions would be achieved in a relatively short time.

Another commenter (OAR-2002-0056-2922) also recommended that a mercury cap-and-trade program be implemented in three phases. This commenter's recommendation as described in the following paragraphs was identical to the recommendation of the above commenters (OAR-2002-0056-2054, -2422, -3198) with the exception of the Phase 2 (interim) cap. The commenter submitted that in Phase 1, there should not be a numeric cap on mercury emissions. Instead, mercury emission reductions would be those resulting from coal-fired power plants' installing new control equipment to comply with the requirements of EPA's proposed Clean Air Interstate Rule (CAIR), assuming that EPA promulgates that rule. Mercury trading would not occur during Phase 1. The commenter stated mercury allowances would not be issued and banking of mercury allowances would not occur.

Under the commenter's (OAR-2002-0056-2922) approach, coal-fired units would install and certify mercury monitors in 2008 and begin to monitor mercury emissions in 2009. The commenter stated the main reason a numeric cap should not be established in Phase 1 is because there is no way to predict the level of mercury reductions that would be a result from utilities' efforts to meet the CAIR requirements. The commenter believed not setting a numeric limit would avoid excess banking of allowances if the cap were set too high, and conversely, compliance problems if the cap were set below the level of mercury reductions actually achieved from complying with the CAIR. Phase 2 would begin in 2015 with a cap of 24 tons of mercury emissions per year. The commenter submitted that in Phase 2, mercury allowances would be allocated and mercury trading could occur. According to the commenter, allowances should be allocated on the basis of heat input. The commenter suggested heat input multipliers of 1.0 for bituminous units, 1.5 for sub-bituminous units and 3.0 for lignite units. Phase 3 would begin in 2018 with a cap of 15 tons per year. The commenter asserted that the main problems with EPA's cap-and-trade proposal center on the overly stringent limits on new units and the emissions monitoring and compliance requirements.

One commenter (OAR-2002-0056-2718) supported the consensus industry position that EPA implement a three-Phase trading program and proposed a variation of the approaches described above. According to the commenter, EPA should initially set a Phase I nationwide cap to begin in 2010 at 34 tpy but, based on monitoring data collected in 2008, reevaluate whether the cap appropriately captures the Agency's intent to require co-benefits reductions only in the first phase. The commenter noted that several different studies of co-benefits have indicated a Phase I range of removal from 34 tpy to 42 tpy–a significant range of uncertainty that could be addressed through a monitoring program in 2008. The commenter proposed an interim Phase II cap of 24 tpy in 2015 and a Phase III cap of 15 tpy in 2018. The commenter urged EPA to implement flexible cap-and-trade mechanisms that would enable affected sources to achieve the proposed reductions as cost-effectively as possible.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. EPA is establishing a firm cap of 38 tons based on EPA's modeling of projected CAIR Hg co-benefits. EPA believes it is important to establish the cap levels in the final rulemaking to provide affected sources with certainty and time for compliance planning. EPA examined a three-phase approach but conclude its two-phase approach was appropriate. See final preamble for further rationale and Chapter 7 of Final CAMR Regulatory Impact Analysis. For discussion of coal adjustment factors used in determining allocations see responses in section 5.6.1 below.

Comment:

One commenter (OAR-2002-0056-2243) believed that in general, the grandfathering of elevated NO_x and SO_2 emissions should be eliminated. The commenter viewed this as an unfair competitive advantage to existing generators in a supposedly competitive electric market.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. See final preamble for further rationale.

Comment:

One commenters council (OAR-2002-0056-2906) reminded EPA that it is much more cost effective to reduce emissions from large utility units than from smaller industrial size steam boilers. The Council supported the EPA approach of focusing on the more cost effective larger units as in the proposed Clean Air Interstate Rule (CAIR), formerly known as the Interstate Air Quality Rule (69 FR 4566, January 30, 2004 and 69 FR 32684, June 10, 2004) to achieve the required emissions reductions rather than on higher cost industrial size units.

Response:

The final CAMR will require Hg reductions from coal-fired power plants. See final preamble for further rationale.

Comment:

One commenter (OAR-2002-0056-3469) noted that EPA's determination of the necessity to regulate Mercury emissions from EGU's is based in part on a report by the National Academy of Sciences (NAS). However this report stated that "based on estimates of methylmercury exposures in the U.S. populations... the risk of adverse effects from current methylmercury exposures in the majority of the population is low." Methylmercury is typically found in fish. The commenter further noted that EPA itself has acknowledged that concentrations of methylmercury in fish come from a variety of sources including global natural and manmade sources. According to the Electric Power Research Institute, of the 5,500 tons of mercury emissions estimated to occur globally, only 150 tons originate in the U.S. In the 1997 Mercury Study Report to Congress, the EPA estimated that U.S. EGU's "account for roughly 1 percent of total global emissions" (approximately 48 tons) and emissions of mercury from lignite-fired plants is less than 10 percent of that 1 percent. The report went on to say that "the relationship between mercury emissions reductions from Utility Units and methylmercury concentrations cannot be calculated with confidence." The commenter submitted that computer models run by U.S. EPA and EPRI predict that cutting mercury emissions from power plants by 50 percent will only reduce mercury levels in U.S. waters by an average of 3 percent and this level of reduction will translate into a reduction of less than 1 percent in exposure to mercury via fish consumption.

The commenter believed the EPA is faced with a dilemma. On the one hand the science does not yet point to a direct link between U.S. EGU mercury emissions and methylmercury concentrations in fish nor does science show how reductions in EGU mercury emissions will alter these concentrations and lower health risks. On the other hand, the public has been led to believe that mothers and unborn children are at risk to exposure of damaging levels of mercury due to consuming fish and that this mercury emanates from U.S. power plants. It is asking for action to be taken to control mercury emissions from power plants.

The commenter stated that given the state of the available information, it would thus appear prudent on the part of EPA to proceed slowly, implementing cost-effective regulations that do not destabilize energy markets, such as forcing fuel switching or inhibiting the construction of new coal-fired generation, or imposing unintended social or economic costs, such as raising energy prices and closing mines and power plants in rural areas. (These consequences are discussed in detail in the comments submitted by CEED and are incorporated in the commenter's comments by reference). The commenter submitted that a measured approach will allow the EPA to evaluate the effectiveness of the regulations in reducing health risks and to modify future regulations in light of these results. To demonstrate it is a good steward of the public's health and resources, EPA must be able to conclusively demonstrate that the regulations have resulted in lower health risks. The commenter concluded that as such a phased approach to regulation is called for.

Response:

EPA is finalizing a cap-and-trade program under section 111, and establishing a first phase cap of 38 tons and a second phase cap of 15 tons. See final preamble for further rationale.

Comment:

One commenter (OAR-2002-0056-1842) offered the following "mercury escalating payment proposal." According to the commenter, the high mercury emitters would pay the low mercury emitters' amounts which would rise each year. The commenter submitted that if 90 percent of the mercury could be removed for a rate increase of one percent, the vast majority would support the expenditure. If a modest rate increase would achieve 80 percent reduction while a huge increase would be needed for 90 percent reduction then the vast majority would support the 80 percent removal. So there would be relatively little controversy over how much should be spent. The commenter believed the controversy would be over cost vs. performance. The commenter noted environmentalists say 90 percent of the mercury can be eliminated at a cost of a few thousand dollars/lb. Utilities say that even at $35,000/lb you may not be able to remove 90 percent.

The commenter stated that at the end of the year each utility who emits mercury at greater than the average rate pays into a fund and each utility under the average receives those payments. The amount per pound would rise each year. The commenter submitted it would likely start low, e.g., $5,000 lb in 2007 and rise at $10,000/lb per year until industry-wide emissions are reduced to 5 tons/yr.

The commenter submitted that if the environmentalists are right and most mercury can be removed for a few thousand dollars/lb, then utilities would soon invest in removal technology rather than pay into the fund. To ensure that this does happen the rule could contain a proviso that if mercury is not reduced to some level (e.g. 25 tons in 2010 and 5 tons in 2015) then a tax would kick in. The commenter suggested this tax/lb would be greater for those with higher than average emissions. The funds from this tax would be earmarked for mercury development.

The commenter believed setting the cost/lb would be critical. The commenter noted that interestingly both sides in the argument would have to contradict themselves. Environmentalists would say that instead of a few thousand dollars/lb it could be very costly. Utilities would say that the payment costs should be set lower and will have to base this on the claim that mercury can be removed cheaply.

The commenter admitted that the truth of the matter is that setting the costs would be tricky. At $19,000/lb average cost it would appear that a $25,000/lb top payment would be sufficient. But the commenter submits that given the incremental cost structure above, utilities would stop at 75 percent efficiency. The commenter suggested it might be best to set $85,000/lb as the payment in 2015. According to the commenter, this would result in more than 80 percent removal.

The commenter explained the steep escalation for the final percent is based on increasing carbon usage from 2 Lbs/MMacf to 10 lbs/MMacf to 30 lbs/MMacf. The commenter did not believe carbon would be used at the high usage rates. The commenter believed this escalating payment system will stimulate all sorts of developments. The commenter submitted one of the main attractions of this approach would be the accelerated use of better technology. The commenter pointed to chloride pre-scrubbers, biomass gasification including PVC for injection as a reburn fuel, additives other than carbon, acid condensation, etc. The commenter stated all would promise to remove 90 percent of the mercury at less than $10,000/lb.

Escalating Payment Scenario Would Also Solve Monitoring Problem. The commenter submitted the EPA proposal to ignore particulate mercury was not a good idea. The commenter noted that three percent error is maybe acceptable for emission reporting but if you are trading allowances at $35,000 or as per above $85,000/lb (NOTE: The $85,000/lb figure is based on an example application of the mercury escalating payment proposal given in the comment), you are talking about a variance of $100 million to $200 million. Furthermore, there is no assurance that three percent is the right number. The commenter pointed out the RJM concept is to condense acid mist on fine particulate in order to create acid deposition sites. Under the EPA scheme all the mercury could then be discharged and not counted. The commenter also pointed out there is a 10 times differential between fine particulate emissions from old precipitators and new ones.

According to the commenter, no trading system will stand for this amount of inaccuracy. So the commenter proposed an "audit system." EPA can protect against abuses but put the burden on the utilities to report accurately. The commenter submitted that because of the financial consequences utilities will demand a measurement system which provides the highest possible accuracy. EPA has already proposed allowing better QC/QA rather than mandating specific instrumentation. The commenter believed this is the route to take.

Investors Will Supply the Capital and Take the Risks. The commenter stated most experts agree that mercury technology lacks the certainty of SO_2 removal. But they would also agree that there are many probable routes to economic mercury removal. The commenter submitted the problem is that utilities do not have the mind set of traders. So why not pass the risk to the investment community. The commenter pointed out the maximum cost per pound in any future year is now known. The investor would agree to receive some percentage of this amount. In return he would finance the control technology used to make the reductions.

The commenter believes there is a big upside profit potential and a limit on downside risk. In a worst case scenario the investor would lose his investment but does not face additional penalties. The investor says that if the system works he wants the lion share of the cost difference. If it doesn't work the utility just makes the payments they would have made without the investment.

The commenter raised the question, How does a proposal such as this meet the criteria of individual action by each state? One way would be to add a clause that each state that volunteers to enter this plan would have the option to drop out when mercury limits reach the budgeted amount in the state. The commenter believes in practice no state would do so.

The commenter submitted the reason would be if the state reached this threshold, utilities in the state would be net recipients rather than payers. So opting out would increase electricity rates.

The commenter stated another reason no state would drop out is that this plan would encourage cost effective mercury reductions beyond the 90 percent. The commenter stated, e.g., the national average drops to five tons in 2015. At that time the payment price of $85,000/lb would no longer escalate, but the payment would continue at that price. The commenter submitted that in future years, new technology that costs less than $85,000/lb would be implemented. The commenter believed that eventually mercury might be reduced by 95 percent instead of 90 percent. The beauty is that the cost would be a maximum of $85,000/lb for the last increment and on the average only a fraction of that. The commenter stated that their analysis showed that the cost for very high mercury reduction will be only 1 to 2 mils/kWh.

The commenter (OAR-2002-0056-1842) stated that the Particulate Inter-Utility escalating payment plan would provide a cost effective solution to the particulate and toxic metal problems. The commenter submitted that higher emitting utilities would pay lower emitting utilities an amount starting at $400/ton in 2007 and amounts in future years which escalate at $400/ton until national averages drop below 0.05 lbs/MM/btu. According to the commenter, an analysis showed that within a few years, payments would be more than the annual cost of efficient particulate control equipment. The analysis also showed the substantial reduction in toxic metals which would accompany the particulate reduction.

Response:

EPA is finalizing a cap-and-trade program under section 111 that it believes is appropriate and cost-effective.

5.4 HOT SPOTS

Comment:

A trading scheme would allow dirty plants to continue to emit high levels of mercury by purchasing credits from cleaner plants and not installing controls, which would further endanger the health of surrounding communities. with hot spots. For example, one commenter (OAR-2002-0056-2355) stated that low income immigrant populations who eat fish from local waters are at risk as are Boston residents who suffer from asthma. The commenters believed this approach is inappropriate for such a toxic pollutant and is inconsistent with EPA's own findings as well as other Federal agencies such as FDA and NAS. Another commenter (OAR-2002-0056-4139) submitted information suggesting that localized deposition impacts do occur. The commenter attached a copy of the USGS briefing. The commenter stated that the data suggest that monitored mercury wet deposition is directly related to the quantity of mercury emissions within 50 km.

One commenter (OAR-2002-0056-4177) opposed a cap and trade approach under section 111 or 112. The commenter submitted that State ambient monitoring shows that mercury emissions create hot spots downwind of sources. The commenter believed a national trading program would doom certain areas of the country to unacceptably high concentrations. Given the current concentrations in the Northeast, the commenter felt Maine would likely continue to be located in a hot spot.

The commenter (OAR-2002-0056-3449) stated mercury emissions remaining after compliance with a cap and trade program would cause unacceptable adverse health effects; hot spots would remain. The commenter noted that EPA's rationale stressed that the health risks associated with mercury emissions from power plants are uniquely global, rather than local . According to the commenter, this dismisses the importance of local impacts from heightened deposition near power plants and the regional impacts from overlapping deposition pattern. The commenter submitted that in general, regions with the highest deposition are the same regions where local and regional sources make significant contributions to the total mercury load. It was clear to the commenter that mercury emitted from coal-burning power plants is deposited much more in some areas than other. The commenter submitted that a cap and trade approach would exacerbate the regional impacts. The commenter noted that about 30 percent of generating capacity has shorter stacks that tend to result in more local deposition. These are typically smaller, older plants that would not likely be controlled under a cap and trade program. The commenter believed regional and local impacts could increase in regions where these plants are prevalent. The commenter stated large hot spots exist now across areas too big to be called "spots." These include entire regions, especially in the Northeast and Great Lakes. The commenter claimed this is confirmed by deposition monitoring data collected by states and the by widespread fish advisories. The commenter concluded that marginal regional decreases would not solve the regional or local problems. In some cases, emissions may increase if plants increase coal use.

One commenter (OAR-2002-0056-3435) stated EPA should abandon cap and trade because of its weakness in control of a HAP and concern for possible hot spot problems. The commenter submitted that recent studies (New Jersey Mercury Task Force Reports, Mercury Emissions from Coal-fired Power Plants by NESCAUM, and Integrating Atmospheric Mercury Deposition with Aquatic Cycling in South Florida have shown that mercury is deposited much closer to the source of emissions than NO_x or SO_2 emissions and poses a much greater health and environmental impact. The commenter noted that Georgia already has areas of high mercury concentrations in the southern part of the state where physical and chemical conditions favor metethylation and bioaccumulation of mercury. The commenter believed utility units within these airsheds must reduce emissions to the maximum extent possible. The commenter asserted that any aspect of a program that would allow less than maximum control is unacceptable.

Several commenters (OAR-2002-0056-2817, -2819) supported MACT standards under CAA section 112(d) to address mercury hot spots associated with emissions of oxidized mercury from coal-fired boilers. One of the commenters (OAR-2002-0056-2817) contended that while science may not be conclusive on some aspects, EPA should err on the side of public health and adopt more stringent limits. The commenter cited potential legal concerns, the hazardous nature

of mercury and the potential for hot spots as reasons EPA should abandon the cap and trade approach. The commenter believed cap and trade may be appropriate for regional pollutants such as SO_2 and NO_x, but not for HAP.

One commenter (OAR-2002-0056-3210) stated that EPA's conclusions about the benefits of a cap and trade program for mercury do not reflect current science, environmental considerations, engineering, or economics. The commenter noted the Utility RTC concluded that the Great Lakes, Ohio River Valley, the Northeast, and scattered areas in the South are predicted to have the highest annual deposition rates. The commenter also noted that recent studies show that US sources are the main contributors. The commenter believed the cap and trade program would promote hot spots and allow continuation of regional concentrations. The commenter stated that regional concentrations could be reduced much sooner through appropriate MACT standards.

One commenter (OAR-2002-0056-2878) opposed cap and trade and cited several scientific and policy concerns including lack of safeguards to protect the public health and secure additional needed reductions, toxicity of mercury and tendency to bioaccumulate in the food chain, potential for hot spots, and environmental justice. According to the commenter, an initial analysis showed that the top 33 percent of the largest plants have stack heights about twice as tall as the bottom 33 percent lowest emitters. Short stacks could contribute to more local deposition. The commenter submitted that to the extent that trading shifts emissions from larger to smaller plants, the maximum local deposition would be about 4 times higher for each pound of mercury.

Several commenters (OAR-2002-0056-2219, -3526) opposed the cap and trade approach because it would have disproportionate impacts on the Great Waters, including the Great Lakes region and worsen existing hot spots and may cause new ones. One commenter (OAR-2002-0056-2219) stated that not requiring controls on all facilities would further contaminate important food supplies for sensitive populations already impacted by the largest concentration of coal-fired power plants in the U.S. According to the commenter, except for the Everglades, the Great Lakes have the highest mercury deposition rate in the world. According to an EPA mass balance study, 86 percent of mercury deposited to Lake Michigan comes from atmospheric sources–30 percent of these emissions are from local sources near Chicago and the number of potential local sources of mercury is increasing. The commenter claimed that the health of women, children, and other sensitive populations will be at further risk. The other commenter (OAR-2002-0056-3526) stated that cap and trade is inconsistent with EPA's prior determination that it would protect the Great Waters through faithful enactment of section 112 without a cap-and-trade approach (63 FR 14090, March 24, 1998). The commenter noted that a cap and trade approach would not guarantee that units responsible for mercury and other HAP pollution to the Great Waters would have to adopt mercury controls. section 112(m) of the CAA prohibits EPA from adopting a program to control HAP that does not assure adequate safeguards for the Great Waters. The commenter asserted the cap and trade program can not address the adverse impacts that units currently have on the Great Waters and could result in even more harm. The commenter stated that if EPA does adopt a cap and trade program, it must explain how this approach fulfills its nondiscretionary duties to protect the Great Waters.

One commenter (OAR-2002-0056-2219) opposed the cap and trade approach because scientific understanding of the percentage of mercury that is converted to methylmercury (the form that most readily enters the food chain) is limited. The commenter noted that results of the Florida Everglades study showed that reducing emissions on a regional basis, facility by facility, would achieve reductions in the ecosystem, but it is not a one-to-one correlation. In this study, a 99 percent reduction in emissions from incinerators yielded a 60 percent reduction of mercury in fish tissues. The commenter stated it is not clear that a cap and trade program would achieve the significant local reductions needed to improve the ecosystem. The commenter believed if all facilities reduced emissions, then local and national emissions would also be reduced. The commenter also stated that mercury emissions must be addressed on a facility-by-facility approach since the most toxic form of mercury (reactive gas phase mercury or RGM) is deposited locally. According to the commenter, trading schemes would create regional areas of higher mercury releases that would further damage food sources and human health–particularly in the Great Lakes area where there is a high percentage of subsistence fishing.

According to the commenter (OAR-2002-0056-3437), The 2003 results of the EPA Office of Water study, "Draft Mercury REMSAD Deposition Modeling Results" reinforced their concerns. This modeling showed that at mercury hot spots, local emission sources within a state can be the dominant source of deposition, commonly accounting for 50-80 percent of the mercury deposition. According to the commenter, in state sources contributed more than 50 percent of the pollution to sites in the top 8 worst hot spot states (Michigan, Maryland, Florida, Illinois, South Carolina, North Carolina, Pennsylvania, and Texas).

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

Many commenters (OAR-2002-0056-1625, -1627, -1673, -1790, -1859, -1969, -2251, -2332, -2431, -2547, -2560, -2578, -2725, -2830, -2833, -2835, -2841, -2850, -2861, -2862, -2897, -2900, -2907, -2915, -2918, -2922, -2929, -2948, -3353, -3444, -3463, -3478, -3513, -3530, -3537, -3539, -3546, -4891) believed that a mercury cap-and-trade program will not create hot spots. Many of these commenters (OAR-2002-0056-1625, -1790, -2251, -2547, -2560, -2725, -2833, -2835, -2897, -2900, -2915, -2922, -2948, -3353, -3463, -3513, -3539) cited review of recent studies as directly refuting that claim.

Several commenters (OAR-2002-0056-1625, -2915) stated there are several facts that suggest that localized effects will not occur with a mercury emissions trading program. The commenters pointed out that mercury emissions from utilities in the U.S. represent only a portion of emissions–less than 10 percent of total North American emissions and about one percent of total global mercury emissions. Regulations or legislation will make this small contribution even smaller. According to the commenters, a recent study by EPRI found that reducing power plant generation mercury emissions will produce minimal benefits–a 47 percent cut would yield less

than a one percent drop in exposure. The commenters submitted that even drastic reductions in utility mercury emissions will have a minimal effect on state fish advisories. Furthermore, most power plant mercury emissions are of the elemental form soon after release and therefore enter the global pool instead of depositing nearby. The commenters cited a recent study by Brookhaven National Laboratory that found only 4 to 7 percent of mercury is deposited locally. Another fact presented by the commenters is that regulations to control SO_2 and NO_x will require the installation of pollution controls that will also capture the forms of mercury that tend to deposit nearby. This is because the species of mercury that are deposited locally-oxidized and particulate mercury-are controlled by the same equipment that controls fine particles, SO_2 and NO_x.

Another commenter (OAR-2002-0056-3478) stated that current research indicates that North American anthropogenic sources were calculated to contribute only from 25 to 32 percent of the total mercury deposition over the continental U.S. The commenter stated that the amount of local deposition of mercury is in part a function of the speciation of the mercury emitted from the source. The commenter further stated that mercury is typically emitted both in its elemental form and as oxidized mercury. According to the commenter, elemental mercury tends to enter the global mercury cycle, and may be retained in the atmosphere for up to one year before deposition, creating the possibility that it will travel around the earth several times before deposition. Similarly, one commenter (OAR-2002-0056-1859) agreed that no hot spots should occur, particularly as it pertains to units in the west and to facilities that burn sub-bituminous coals. The commenter noted that sub-bituminous coals are typically low in SO_2 and mercury and when combusted, produce primarily elemental mercury which tends to not deposit near the source.

One commenter (OAR-2002-0056-2431) cited modeling by EPA, DOE, the Brookhaven National Laboratory, and EPRI and concluded that emissions trading would not create hot spots. The commenter claimed that studies of the acid rain program trading program demonstrated that trading did not significantly change where emissions actually occurred when compared to a command and control approach. The commenter stated trading would not cause local impacts because most emissions become elemental soon after release and enter the global pool instead of depositing nearby. Also new SO_2 and NO_x rules will require controls that also capture the forms of mercury that tend to deposit nearby. The commenter further submitted that overall emissions would still decline even if some utilities did not install controls because of the cap. The commenter stated that emissions trading also creates economic incentives which bring about the greatest reduction from the highest emitting sources. The commenter concluded thus, hot spots would not occur.

One commenter (OAR-2002-0056-3513) pointed out that EPRI modeling has indicated that mercury should be studied on a global scale–not a local or even national one. EPRI's analysis showed that the majority of mercury emitted from coal-fired units is in the elemental form which does not deposit locally, but enters the global pool and circulates in the atmosphere for six months to a year on average. The soluble forms of mercury are more likely to deposit nearby. The commenter submitted however, if the proposed rule is enacted along the same

timeline as the Interstate Air Quality Rule, most units will be required to install SCR's and/or scrubbers which will capture most soluble forms of mercury.

One commenter (OAR-2002-0056-2835) stated that the acid rain program has cost effectively achieved a 41 percent reduction in SO_2 emissions from 1980 through 2002 (despite a significant increase in electric generation) and done so without any evidence of local "hot spots" occurring. The commenter also pointed out that the NO_x SIP Call rule has adopted an interstate cap-and-trade program that has achieved significant reductions in NO_x emissions from the power sector.

Several commenters (OAR-2002-0056-2251, -2833, -2948, -3530) submitted that as "proof" of the "hot spot" theory, some groups have cited a study of mercury in the Florida Everglades. According to the commenters, many claims about this study contain erroneous, unsubstantiated assertions that it "proves" controls on local sources would result in a fairly rapid decline of mercury in the regional environment. The commenters asserted the study does not prove such assertion because:

- The mercury reductions in south Florida were from municipal and medical waste incinerators, not from power plants. The mercury emissions from these incinerators are generally in a water-soluble form.

- Many studies have shown that the characteristics of the water body, not the amount of atmospheric deposition, dictate the eventual levels of mercury in fish. The Everglades is a unique ecological and climatological system, strikingly different from other U.S. waterbodies; it should not be considered representative of water bodies in other states, or even of other parts of Florida. Before states decide to take action beyond the federal mercury rules, they should assess their state's actual situation.

- The claim that changes in mercury emissions will result in rapid changes in the amount of methylmercury found in fish is not supported by the study's data or findings. Despite decreases in mercury emissions from incinerators, data measurements and long-range transport modeling indicate that the amount of mercury being deposited in the Everglades overall has changed little. Modeling of mercury transport conducted by EPA and EPRI has led to the conclusion that over 60 percent of mercury deposited in Florida originates outside the state.

- Extensive measurements around power plants have failed to show local increase in mercury at ground level or in nearby waterways. EPA reached this conclusion in its 1997 Mercury Study Report to Congress, and this finding has been supported by recent studies at a large power plant in Maryland.

The commenters concluded that clearly, the Florida Everglades study does not support applying the "hot spot" theory to other states, or even other parts of Florida.

Regarding the South Florida Report, another commenter (OAR-2002-0056-3444) had several comments. The commenter referenced several commenters that suggested that this Report demonstrated the existence of "hot spots" and further demonstrated that limiting mercury releases from coal-fired power plants (CFPPs) would cause rapid decreases in mercury concentrations in the local/regional environment. The commenter submitted that neither conclusion followed from the Florida report. While the commenter acknowledged an extensive and valuable body of research has been conducted in south Florida, the commenter found two major problems with how the results have been interpreted (both in the report itself and by others). First, to what degree has the relationship between local mercury emissions reductions (known to have decreased dramatically between the late 1980s and the early 1990s) and decreasing levels of mercury in biota (documented to have occurred between the early 1990s and the present, but not to the same degree everywhere in south Florida) been established, or put another way, how much of the latter was caused by the former? Second, to the extent we know this relationship, to what degree does it apply to CFPPs in other parts of the country?

The commenter stated that relative to the first issue, while there is an evolving weight of evidence that there is some relationship between local mercury emissions reductions and local biotic response, the degree of the relationship has not been, nor can it be, definitively quantified for the time period addressed by the Florida study. First, the commenter noted there is no deposition record spanning the time before and after the emission reductions. Inferences from sediment cores are, at best suggestive, and at worst inconsistent. Second, the commenter submitted that while aquatic model hindcasting (currently being conducted) suggests a link between deposition and response in aquatic biota, it cannot allocate the share of deposition changes coming from other source changes and the share of the biotic response coming from non-depositional ecosystem changes (e.g., hydrological, sulfate, phosphorous, DOC, etc.). To the extent that U.S. emissions reductions, European emissions reductions, and other worldwide emissions changes were affecting the changes in deposition at the same time (also a study in progress), it would moderate the degree that local emissions changes were having on deposition changes. The commenter also stated that similarly, to the extent hydrological and other ecosystem changes were also affecting biotic mercury levels, it would moderate the role of deposition changes. Finally, the commenter believed atmospheric modeling conducted as part of the Florida Study was flawed in several ways. The modeling erroneously assumed that mercury deposition in waterways comes only from local sources. The commenter noted that modeling by EPA and EPRI has shown that more than 90 percent of the mercury that currently deposits in south Florida originates outside the United States. The commenter conceded that in the late 1980s it is likely that the local contribution was somewhat higher than today, it could not have been 100 percent. The commenter summarized, the magnitude of the connection between local mercury emissions reductions in south Florida and local biotic response is tempered by the contributions from other mercury emissions changes worldwide and other ecosystem changes affecting the biotic response.

Relative to the issue of extrapolation, the commenter stated there are numerous arguments why the results cannot be extrapolated to CFPPs in other areas of the country. The commenter submitted that whatever relationship that may exist is unique to the type of emissions, the climatology, and the type of ecosystem that exists in south Florida. First, as

demonstrated above, we don't know the magnitude of the connection between local mercury emissions and local biotic responses. Second, municipal and medical waste incinerators–not power plants–are the source of industrial mercury emissions in south Florida that are referenced in the Florida report. Incinerators produce far higher percentages of ionic mercury–the form of mercury that is water-soluble and more readily deposited–than coal-fired power plants and have far shorter stack heights resulting in the potential for higher amounts of mercury being deposited near these sources. Third, there is evidence that ionic mercury emissions from CFPPs rapidly converts to elemental mercury–the form of mercury having a long atmospheric residence time–a phenomena not observed in incinerators, which suggest that the link between emissions and local deposition would be even less for CFPPs. Fourth, the climatology of south Florida is unique to the U.S. with daily, deep convective thunderstorms that converge over the Everglades in the summer. Fifth, the Everglades are not representative of U.S. waterways because they are in a subtropical zone with no distinct seasons and high rainfall in the summer, contain shallow water with very low flow rates, and with bottom sediments that differ from those in other locations. Other waterbodies also have different levels of acidity, biological activity, dissolved oxygen, and turbidity. The commenter asserted that all of these differences could dramatically affect mercury cycling and uptake by biological organisms and make extrapolation of the Florida results to other areas of the country inappropriate. The commenter pointed out that in Minnesota, for example, mercury emissions also have declined dramatically from 1990 to 2000 (about 68 percent–Minnesota Pollution Control Agency, March 2004), yet mercury in fish of that area has not changed significantly in the last 15 years. The commenter summarized, the extrapolation of the Florida mercury emissions to deposition or deposition to biotic response relationships, to other sources and areas of the country is inappropriate.

The commenter stated, accordingly, the Report cannot justify a conclusion by EPA that coal-fired power plants create local "hot spots" nor can the results be extrapolated to CFPPs in other parts of the country. The commenter added that the Report itself recognizes its limited focus and is replete with assumptions, caveats, cautions and recommendations for further work, none of which is mentioned in the references or citations above. More detailed comments regarding the Report are summarized as follows:

- The analysis upon which the Report relies is a work-in-progress, and therefore the conclusions are at least premature. The Report expressly recommends that further information be obtained and provides seven specific cautions when interpreting the results.

- Any claim that cost-effective control strategies have substantially reduced mercury concentrations in south Florida's fish and wading birds is premature. A research project in excess of $300,000 has been designed specifically to shed light on this assertion, that is, to elucidate between competing hypotheses for explaining the observed reduction of mercury in south Florida's biota.

- Not all ecosystems are created equal. Mercury may be accumulated up the food chain differently in other ecosystems than in the Everglades. To the extent decreases in local reactive mercury emissions result in local declines in concentrations in fish and wildlife

might be true in the area of study (central Everglades), there are substantial differences in responses even across the Everglades ecosystem. There is also evidence of a general decline in mercury in biota in areas that are remote from local sources.

- While it may be true that total quantities of mercury emitted from CFPPs are substantially larger than that of incinerators on a world-wide basis, the form of mercury emitted from coal plants is more in a form (non-reactive) not readily deposited on a local scale. In addition, recent research indicates that any reactive mercury that is emitted from coal-fired power plants is largely transformed to the non-reactive form before deposition can occur. Furthermore, a press release from the Resources Committee, US Congress, states that U.S. coal-fired power plants emit only 1 percent of the total global mercury emissions, citing peer-reviewed research published in Atmospheric Environment, 2003. In addition, emissions measurements analyses show that the data quality varies widely between different sources and geographically.

- The Report describes impressive reductions in mercury emissions achieved by municipal waste incinerators and by the closing of numerous small medical waste incinerators. These reductions and the implied reductions in mercury inputs to the Everglades ecosystem must be considered in the context of the high percentage of reactive mercury emitted from these facilities, 75 percent and 95 percent, respectively.

- The Report does not support the idea that the Lake Annie (sediment core) data shows a peak in deposition coinciding with the peak in emissions, followed by a rapid decline consistent with emission reductions from the Dade and Broward County incinerators 150 miles away. The implication that emissions from the Dade and Broward County incinerators affected mercury accumulation in the Lake Annie cores is not supported. Researchers have postulated that mercury reduction effects can be seen 60 miles from an emission source. However, prevailing winds from Dade and Broward counties are unlikely to cause consistent depositional impacts in an area northwest of Lake Okeechobee. In addition, the magnitude of decrease (assuming it has been corrected for focusing and rainfall) was small and should have been noted as evidence for local sources not playing much of a role.

- A modern and retrospective study of mercury in feathers from wading birds is cited as following the pattern of mercury emissions from 1920 to 2002. However, a modern and retrospective study of mercury content in hair of raccoons (Porcella et al., 2004) failed to demonstrate a significant difference over the last 50 years in south Florida. However, a large difference existed between sites (up to a factor of 20) for raccoon hair mercury in both modern and historic samples. The difference between the wading bird data and the raccoon data may be due to a broader sampling area for raccoons (across the entire south Florida peninsula), compared to feather collections from specific rookeries.

- The idea that reductions in mercury deposition will be more dramatic closer to Broward and Dade counties where the majority of emissions reductions from incinerators occurred

is also not supported. Specifically, the Florida Atmospheric Mercury Study (referred to in comment g) results do not bear this out.

- Finally, the South Florida Report characterizes mercury as a "now well-understood neurotoxin." This is certainly arguable since major studies of neurological effects of prenatal mercury exposure in children are not in agreement. No one seriously disputes the fact that, at high levels of exposure and in laboratory settings, mercury is toxic to the brain. However, setting an exposure limit for regulatory purposes should use the best data available from the most realistic and broadly generalisable studies.

One commenter (OAR-2002-0056-2251) claimed that new research from Michigan, a state with significant coal-based electricity generation, further discredits the "hot spot" theory. A March 2004 study conducted for the EPRI by Atmospheric and Environmental Research, Inc. found that "Mercury emissions from Michigan coal-fired power plants are calculated to contribute between 0.5 and 1.5 percent to total mercury deposition over each of the Great Lakes and about 2 percent statewide". The commenter enclosed a copy of this study, Modeling Deposition of Atmospheric Mercury in Michigan and the Great Lakes Region.

Several commenters (OAR-2002-0056-2251, -2833, -3530) also noted that according to the rule's preamble, EPA "does not expect any local or regional hot spots" if it selects the cap and trade approach and will consider using trading ratios to address regional differences if they occur. The preamble also made it clear that states will have the ability to address any remaining local health-based concerns if the EPA selects the section 111 cap and trade option. The commenters pointed out that indeed, the Clean Air Act provides states with discretion to enact more stringent air quality regulations than required by the Act, with the exception of certain limitations for automotive emissions. States would be free to develop specific mercury control strategies to supplement the final federal rule, regardless of its form or level of stringency.

Several commenters (OAR-2002-0056-2830, -3463) believed that mercury allowance trading will not cause adverse local environmental or health impacts because most power plant mercury emissions become elemental mercury soon after release and enter the global pool instead of depositing near the power plant from which it originates. Commenter OAR-2002-0056-3463 stated that elemental mercury is not as likely to be deposited locally as is particulate and oxidized mercury. According to the commenter, a comparison of "Wet Deposition" data to "Total Mercury Concentration" data from the National Atmospheric Deposition Program/Mercury Deposition Network documents strongly supports the conclusion that deposition is more a function of precipitation than proximity to emission sources. The commenter also pointed out that the proposed IAQR rules to control SO_2 and NO_x will require the installation of pollution controls that also will capture the forms of mercury that tend to deposit nearby.

One commenter (OAR-2002-0056-3353) stated that based on the known science of mercury transport, transformation, and health effects, the Agency proposal to control mercury by a cap and trade program is appropriate and health protective. The commenter presented extensive information on the science of mercury (see section 6 of e-docket item

OAR-2002-0056-3353) supporting the commenter's belief that a cap and trade approach will not endanger public health or result in hot spots of mercury health risk. The commenter stated that it will, on the other hand, encourage the continuing development of low cost mercury controls. As the program proceeds and experience is gained with various control options, the commenter believed the cost of control will be explicitly identified.

One commenter (OAR-2002-0056-2431) supported the cap and trade approach because mercury exposure does not present a public health concern warranting stricter regulation under a MACT standard. According to the commenter, recent research by the CDC indicated that people are not being exposed to unsafe mercury levels and the recent Seychelles Child Development Study assessments at 9 years of age show no detectable adverse effects. The commenter also pointed out that in the December 2000 regulatory finding, EPA was unable to quantify the connection between utility mercury emissions and mercury in fish, citing only a "plausible link."

One commenter (OAR-2002-0056-2578) claimed to have performed an extensive modeling exercise with state-of-the-art tools and data to explore projected deposition patterns under both regulatory proposals. The commenter's analysis showed that:

- The highest levels of mercury deposition anywhere in the continental United States are brought about primarily by non-utility sources (even after accounting for MACT rules on those non-utility sources).

- The Cap & Trade proposal would produce larger and more widespread reductions in mercury deposition compared to current emissions than would the MACT proposal, particularly in regions with the highest deposition currently.

The commenter also cited increasing evidence from laboratory, pilot-scale, and full-scale measurements that the divalent form of mercury may convert to the far less soluble elemental form within power plant plumes and that this apparently rapid and complete conversion would reduce local scale deposition from power plants significantly, if it is found to hold for a wide range of such sources. To verify these preliminary results, the commenter undertook a field program at two power plants using a combination of aircraft measurements, surface observations, in-plant measurements, and coal sampling. At both power plants from the stack to downwind sampling locations, the commenter reported a significant increase in the elemental mercury concentration and a corresponding decrease in the divalent mercury concentration. According to the commenter, these initial demonstrations of the significance of a potential reduction reaction may imply that utility power plant mercury emissions contribute less to downwind wet deposition than has been assumed previously.

One commenter (OAR-2002-0056-2862) stated that while there is evidence in the literature regarding apparent linkages between incinerator mercury emissions and enhanced mercury deposition near these sources, extensive modeling work, as well as detailed flue gas chemistry measurements, did not support a similar linkage for coal-fired power plants. Indeed, preliminary results from the EPRI I U.S. DOE -funded plume chemistry work that is currently underway and discussed in EPRI's comments on these proposed rules, strongly reinforced EPA's

assertion that the cap and trade program is unlikely to produce so-called areas of enhanced mercury deposition near coal-fired power plants. Based on these conclusions, the commenter asserted that EPA should not require units in "sensitive" areas to surrender more allowances than units in other areas deemed less sensitive (e.g., requiring some units to surrender two allowances for an ounce of mercury emissions rather than the standard one allowance). Commenter OAR-2002-0056-2948 also stated that EPA should not require units in "sensitive" areas to surrender more allowances than other areas deemed less sensitive because this would significantly and unnecessarily complicate the trading program and would lower the cap. The commenter added that EPA's proposal did not describe how such "sensitive" areas would be defined, and only a very small portion of mercury emissions from coal-fired power plants deposit within 50 kilometers in any event. The commenter stated that adoption of this proposal will only add a great deal of complexity to the program.

Similarly, one commenter (OAR-2002-0056-2861) stated there is no basis for any provision in EPA's mercury rule to require the surrender of more than one allowance per ounce of mercury emissions related to the alleged issue of mercury sensitive areas or "hot spots." The commenter submitted neither EPA nor anyone else has made any demonstration of a linkage between power plants in a given area and elevated mercury deposition or exposure in that area. The commenter added that by nature of the cap and trade program and by nature of how power plants operate, there is no concern that the mercury cap and trade program would create such "hot spots." The commenter noted the cap and trade program at the proposed levels would achieve a significant overall reduction in mercury emissions across the nation. The commenter believed the larger, higher emitting sources are the sources that will be controlled. Requiring the surrender of more than one allowance in certain areas would greatly complicate and confuse the trading program and would result in a lowering of the emissions cap. The commenter stated this also would affect the cost of compliance that was used to establish the performance standard that is the basis of EPA's cap and trade program. The commenter believed such a provision should not be allowed without a clearly demonstrated need and that demonstration would be extremely subjective as it relates to the definition and identification of "sensitive" areas and the sources whose emissions would be deemed to impact those areas and therefore required to surrender additional allowances. The commenter concluded that there is simply no credible way to make such determinations, and in fact EPRI studies of mercury deposition and exposure suggest that such a program would not be justified.

One commenter (OAR-2002-0056-3537) submitted that a mercury cap and trade program would not increase local mercury deposition in waterbodies close to regulated Utility Units and create hot spots. The commenter stated in fact, EPA's analysis showed that, if anything, a cap and trade program would help to protect against potential hot spots rather than aggravate them. The commenter noted that EPA's modeling suggested that large coal-fired Utility Units, which are those units that tend to have relatively high mercury emissions, are likely to have larger local deposition footprints than medium and smaller sized coal-fired Utility Units. However, the commenter submitted that the trading of allowances will probably lead to the over control of mercury emissions at the larger Utility Units and the selling of allowances to smaller Utility Units. Why? According to the commenter it would make more economic sense (due to economies of scale) for a utility to allocate pollution prevention capital expenditures to its larger,

generally more efficient facilities than to smaller, generally less efficient plants. Several other commenters (OAR-2002-0056-1969, -2841, -2861) stated that the most cost-effective reductions will be made first at the larger, higher emitting sources.

The commenter (OAR-2002-0056-3537) submitted second, the types of mercury that are deposited locally–ionic and particulate mercury–are controlled somewhat by the same type of equipment that will be used to comply with the CAIR (i.e., FGD and SCR). These types of mercury are more likely to be deposited locally than elemental mercury, which is emitted in a gaseous form, is not soluble in water, has a relatively long life in the atmosphere and which remains uncontrolled by FGD and SCR. The commenter stated that as utilities invest in equipment to comply with not only the CAIR but also with new national ambient air quality standards for $PM_{2.5}$ and ozone, a co-benefit in mercury control will be achieved. Those co-benefits will be the increased control of ionic and particulate mercury, decreasing even further the extremely small amount of mercury now deposited locally by Utility Units. The commenter claimed, therefore, a mercury cap and trade program would lead to increased control on the forms of mercury most likely to be involved in potential hot spots.

The commenter pointed out that modeling conducted by the Electric Power Research Institute (EPRI) has demonstrated that mercury must be studied and understood on a global scale rather than a national one. The commenter stated that U.S. utility mercury emissions account for only 1 percent of total yearly mercury emissions worldwide. A recent report indicated that the amount of mercury released to the air from the earth's surface each year is estimated to be between 2700-6000 tons, with another 2,000-3,000 tons emitted by human activities, yielding a total amount of mercury that enters the atmosphere each year of 4700-9000 tons. The non-anthropogenic fraction is due to volcanic action, natural weathering and re-entrainment of crustal material and the re-emission of mercury associated with past man-made emissions since the Industrial Revolution. The commenter noted that by comparison, a number of sources estimate current emissions of mercury from U.S. utilities to be approximately 48 tons per year, which is less than 8 percent of the mercury deposited in the U.S. The commenter stated that a 2003 study by EPRI indicated that if ionic mercury emissions from coal-fired power plants were reduced by 10 percent, mercury deposition in the U.S. would decrease by only 0.75 percent. If elemental mercury emissions from coal-fired power plants were reduced by 10 percent, the resultant drop in mercury deposition in the U.S. would only be 0.03 percent.

Finally, the commenter stated EPA noted that States retain the power under the CAA to adopt stricter regulations to address any local hot spots or other problems. Given the 70 percent emission reduction proposed in EPA's cap and trade systems, the Agency noted that it expects no local regional hot spots. The commenter noted however, it also stated that it plans to continue monitoring mercury emissions and the operation of the trading system through its administration of the MATS, to ensure that localized hot spots do not materialize. Accordingly, the commenter believed it is clear that EPA imposition of a mercury cap and trade program, would, if anything, reduce the potential for localized hot spots around affected Utility Units. EPRI provides an extensive discussion on the hotspot issue in their comments and the commenter respectfully referred EPA to this discussion as further evidence that hot spots will not be a concern under a mercury cap and trade program.

One commenter (OAR-2002-0056-3546) submitted that EPRI's most recent research has shown that the highest level of mercury deposition anywhere in the continental United States are brought about by non-utility sources. According to the commenter, EPRI's analysis further demonstrated that the Cap-and-Trade proposal would produce larger and more widespread reduction in mercury deposition than would the MACT proposal.

The commenter stated that it is well understood that mercury is a global pollutant. According to the commenter, EPRI model results showed that approximately 75 percent of the mercury that deposits in the United States originates from sources outside the U.S. For areas in the west, the contribution of global emissions to mercury deposition may be as high as 100 percent. The commenter stated that mercury emissions from coal-fired power plants mercury deposition will not increase in any area as a result of a cap-and-trade program. The commenter noted that modeling work performed by the Electric Power Research Institute predicts that reducing total mercury emissions from coal-fired power plants from present day levels to 15 tons annually will reduce mercury deposition in the United States by 6.9 percent–from 165.4 tons to 153.9 tons per year. The reduction in deposition in western states would be substantially less since mercury deposition from global sources can be as high as 100 percent.

The commenter claimed that cap-and-trade programs promote economically efficient decisions to reduce emissions from power plants. According to the commenter, Units with the highest mercury emissions would be among the first to be controlled since the cost per pound of mercury controlled would the lowest at these units. The commenter noted that this economic behavior has previously been demonstrated in utilities compliance with EPA's Acid Rain requirements and the NO_x SIP call. On a source-by-source basis, the opportunity to trade has led many of the largest SO_2 and NO_x emitters to clean up the most, such that trading has had an effect of cooling potential hot-spots, not creating them.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

Several commenters (OAR-2002-0056-2560, -2897) stated that if hot spots did occur, focused local investigations and some simple constraints would be the best available practice for the accurate identification of contributing localized mercury deposition sources. Commenter OAR-2002-0056-2560 offered as an example, based on the presentation by Opto-Forensics Technologies at the 2004 Electric Utility Environmental Conference in Tucson, Arizona the solution to fish tissue mercury level reductions may well lie in the monitoring and control of mercury emission from municipal landfill vents and not in the reduction of local EGU emissions.

Commenter OAR-2002-0056-2897 offered as another example, EGUs in the immediate vicinity of vulnerable ecosystems could be prohibited from trading, or minimal levels of mercury

reductions at all facilities could be required. The commenter stated this would still allow trading to achieve the greatest reductions where it is cheapest and to incentivize the development of control technology. The commenter asserts that in the unlikely event that hot spots are a serious concern, they can be readily addressed and should not be a basis for giving up the significant benefits offered by a cap-and-trade approach to mercury regulation on a national basis.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

One commenter (OAR-2002-0056-2922) stated that EPA should not require units in "sensitive" areas to surrender more allowances than units in other areas deemed less "sensitive" (e.g., requiring some units to surrender two allowances for each ounce of mercury emissions rather than the standard one allowance per ounce). The commenter submitted that hot spots have not resulted in the Title IV Acid Rain Program, and, as discussed above, no reason exists to believe they will occur in this program. Moreover, requiring different areas to surrender different numbers of allowances would complicate the trading program and result in a lowering of the cap, contrary to EPA's regulatory determinations.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

Several commenters (OAR-2002-0056-1625, -1673, -2547, -2725, -2850, -2929, -3478) pointed out that under a cap-and-trade program, the larger emitters will be the first to be controlled. For example, several commenters (OAR-2002-0056-1625, -2929, -3478) stated that the economics of trading will help to minimize local deposition. The trading of allowances almost always involves large coal-based power plants controlling their emissions more than required and selling allowances to smaller plants. Thus, economies of scale of pollution control investment will favor investment at the larger plants and will produce reductions in emissions at the plants of greatest interest. One commenter (OAR-2002-0056-2725) stated that this is doubly true with mercury; because ionic mercury, the form of mercury that is most likely to be deposited near the plant, is also the easiest and least expensive to control, a mercury trading program would result in emissions reductions at exactly those plants most likely to be responsible for "hot spots. One commenter (2929) noted that the CAIR proposal and other pending state and federal regulations would require the installation of pollution controls that also would capture the forms of mercury that tend to deposit nearby.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

One commenter (OAR-2002-0056-1627) stated that what has emerged from monitoring actual mercury deposition is a far different picture than predicted by many of the early computer models which predicted the presence of hot spots. The commenter submitted that actual data demonstrates that power plants do not significantly affect deposition. The commenter believed hot spots should now be seen to simply be artifacts of the first generation of computer models rather than real occurrences.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

Many commenters (OAR-2002-0056-2173, -2227, -2380, -2415, -2575, -2660, -2817, -2838, -2871, -2880, -2887, -2889, -2878, -2924, -3202, -3413 -3448, -3452, -4177) believed mercury trading may lead to hot spots. One commenter (OAR-2002-0056-2173) noted that concerns about trading are recognized in the regulatory finding, including that the lakes regions of the Upper Midwest may be more sensitive to mercury deposition. The commenter submitted that a recent New Hampshire study suggested that local deposition is very much a concern. However, EPA then claims in the preamble that it does not expect any local or regional hot spots and provides no support or anecdotal arguments in support. The commenter states that hot sports are a real concern in the midwest because of the use of western sub-bituminous coal. It is more difficult and costly to reduce mercury emissions from this coal type than from eastern bituminous coal. Thus, the commenter believed that utilities would be more likely to purchase emission credits from utilities burning eastern coal that have installed controls. The commenter asserted that the result would be that Tribal lands and the entire lakes area of the upper midwest (which is particularly sensitive to mercury deposition and most needing of reductions) may experience little or no benefit. Another commenter (OAR-2002-0056-2227) also noted that EPA's own data show that mercury hot spots exist and are associated with local sources of air pollution.

An alliance of many commenters (OAR-2002-0056-2575) stated that data collected by the North American Commission for Environmental Cooperation show that there are 244 locations in North American where the amount of mercury contamination is greater than that which occurs naturally in the environment. The commenter also provided several examples of the impact of local sources on mercury deposition. and the resulting effects on wildlilfe. The commenter claimed a cap and trade program would only continue and exacerbate mercury

deposition and increase the number of hot spots. The result would be concentration of pollution in certain areas and merely a reallocation of pollution rather than reduction or even an increase.

One commenter (OAR-2002-0056-2838) submitted that in-state and regional sources of mercury in the Southeast contribute to high levels of deposition; four of the top 10 most severe hot spots are in Southeastern states. The commenter believed the cap and trade program has great potential to exacerbate mercury contamination at many sites by allowing large plants to continue emitting; studies show that this mercury would be deposited in-state or within the Southeast region. The commenter stated that according to EPA's Mercury REMSAP Deposition Modeling Results, coastal regions along the Gulf of Mexico and southern Atlantic will require more than 75 percent reduction in air deposition rates to meet EPA's CWA requirements for methyl mercury.

Another commenter (OAR-2002-0056-2878) stated that recent modeling suggests that at mercury hot spots, pollution sources within a state can account for large portions of that deposition. The commenter claimed that at hot spots across the US, local sources often account for 50 to 80 percent of the mercury deposition. The commenter also submitted that in-state sources contribute more than 50 percent of the pollution to sites in the top 8 worst hot spot states (Draft Mercury Deposition Modeling Results, EPA:OW, 2003). The commenter stated that data from the Florida Everglades study showed that local reductions of mercury yielded reductions in mercury pollution. The mercury deposition research in the Florida Everglades, Wisconsin, and southern Ontario also indicated that the majority of mercury converted into methylmercury is from recent deposition, rather than cycling from the sediment, suggesting that reducing mercury emissions from all coal-fired plants is a critical need for reducing exposure and improving damaged ecosystems.

One commenter (OAR-2002-0056-2380, -3413) also stated that earlier modeling showed that local hot spots are the primary sources of mercury deposition within a state, contributing more than 50 percent of the pollution to sites in the top 8 worst hot spot states. The commenter submitted that EPA should include provisions in the rule to address hot spots before they occur.

Many of the commenters (OAR-2002-0056-2660, -2817, -2871, -2880, -2887, -2889, -2924, -3202, -3448, -3452, -4177) referred to the recent Florida study (Integrating Atmospheric Mercury Deposition with Aquatic Cycling in South Florida, November 2003), which showed that sources of mercury can have significant local impacts. This report stated that the drastic reductions in mercury concentrations in fish and birds in the Everglades were directly linked to installation of mercury controls by industries in South Flordia. One commenter (OAR-2002-0056-2819) noted that EPA has already reported that deposition of oxidized mercury can be expected to occur within 50 kilometers of the source; evidence of the existence of hot spots has already been documented in the Evers report (Assessing the Potential Impacts of Methymercury on the Common Loon in Southern New Hampshire) and the Florida Everglades report. The commenter stated that additional evidence of the existence of mercury hot spots can be found on the University of Michigan website at http://www.personal.umich.edu/~kalwali/mich+ohio.html . This website shows color coded maps that distinguish the relative hot spots associated with mercury emissions from local sources

from mercury emissions due to longer range transport (regional sources). The commenter asserted that EPA cannot dismiss these concerns.

One commenter (OAR-2002-0056-2819) submitted recent stack test data showing that 72-94 percent of the mercury emitted by coal-fired boilers is emitted as oxidized mercury. These tests (2003) used the Ontario Hydro method to determine the amount of total mercury and the total amount by species. According to the test data, 2003 annual emissions of oxidized mercury from Merrimack Station units 1 and 2 were 32 pounds and 77 pounds, respectively. Annual emissions of oxidized mercury from Schiller Station units 4, 5, and 6 were 7 pounds. The commenter believed that emissions of this magnitude have the potential to cause local hot spots which can not be remedied solely with a cap and trade program. The commenter submitted that stringent plant-specific MACT limits are needed to address local hot spots. Also, the commenter pointed out that EPA's prediction that small and mid-size units like Schiller and Merrimack Station would likely purchase credits rather than install controls (see 69 FR 4702) confirmed that the cap and trade would not address localized deposition in their state. The commenter believed that the only sure method for addressing hot spots would be to reduce emissions at their source through strict MACT standards. The commenter concluded that it was also a good reason that more stringent limits should apply to all units regardless of size.

One commenter (OAR-2002-0056-2887) contended that EPA has not considered local deposition that can disproportionately affect sensitive ecosystems. The commenter claimed sources that purchase allowances in effect emit uncontrolled levels of all three species of mercury - gaseous elemental, reactive gaseous (RGM), and particulate. The commenter stated trading can worsen existing hot spots and may create new ones near powerplants because the RGM (which can be as high as 70 percent of the total mercury emitted from a bituminuous plant) has relatively short travel distances (up to 50-100 kilometers) and short residence times in the atmosphere (1-2 days), tending to deposit locally near the source. The commenter also noted that recent field studies showed that mercury newly deposited to a zone of methylation in a waterbody is more readily converted to methylmercury. The commenter claimed that, in addition to local impacts, the Northeast is affected by long-range transport of elemental mercury because areas with high ozone levels oxidize elemental mercury and therefore increase mercury deposition throughout the airshed. Further, the commenter cited a report by the New Jersey Mercury Task force which examined local emissions, models, and results, and stated that about half of the mercury deposited in New Jersey comes from relatively nearby sources. One commenter (OAR-2002-0056-4177) cited the NESCAUM Deposition Study which concluded that 47 percent of mercury deposition in the Northeast came from sources within the region, 30 percent from sources outside the region, and 23 percent from the global reservoir. One commenter (OAR-2002-0056-3202) asked EPA to establish more rigorous national standards so downwind states can meet Clean Water Act requirements. One commenter (OAR-2002-0056-3452) submitted a REMAP assessment of mercury in sediments of selected lakes in New Hampshire and Vermont which showed the disproportionate impact of airborne mercury from a power plant and municipal waste combustor.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

Several commenters (OAR-2002-0056-1596, -2330, -2819, -2823, -2871, -2889, -3449, -3499) noted that in the proposal, EPA indicated that hot spots could be addressed through the adoption of more stringent state or local standards. The commenters disagreed and cited their recent survey that showed about half of the state agencies have restrictions on their ability to adopt programs more stringent that those of the federal government. In addition, hot spots can be created across state lines, so that a downwind state is dependent on stricter controls that may be installed by utilities in an upwind state. One commenter (OAR-2002-0056-2819) added that their state relies upon adoption of a strict federal standard under section 112 to establish state limits to meet an annual cap and relying on states to adopt meaningful controls creates an economic disadvantage compared to lax states. One commenter (OAR-2002-0056-3449) asked what these related Federal and State programs are that are supposed to address local risks?

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

Many U.S. Congressmen (OAR-2002-0056-3293) felt that the rule could be strengthened by addressing hot spots now rather than later. The commenters suggested that adding regional emissions trading areas for States with high mercury or setting a level of emissions above which no plant could emit would help protect the public health.

Many state legislators, governors, and local officials called on EPA to strengthen the proposed standards as they are not protective of public health and do not adequately address hot spots. The commenters pointed out that available technology can achieve reductions of 80 or 90 percent. The commenters also pointed out that the emission reductions fall well short of the cuts that could be achieved by 2007 under section 112. One Texas representative stated that no state emits more mercury pollution from its power plants than Texas and no state faces a greater risk from cap and trade than Texas, which could see no emission reduction at all.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

One commenter (OAR-2002-0056-3543) supported the cap and trade program but pointed out that data on hot spots appears scant. The commenter stated that while EPA states it intends to collect data and study the effectiveness of the rule in Phase I and II in order to make any necessary adjustments, it presented no clear strategy for collecting and analyzing information, no solid data on which to formulate a baseline for this analysis, and no strategy for changing the regulatory approach if it aggravates hot spots.

Similarly, one commenter (OAR-2002-0056-2219) disagreed with EPA's suggestion to evaluate mercury hot spots formed as a result of the cap and trade program. As described in the preamble, EPA would evaluate whether emissions remaining after compliance with the cap and trade program cause a health program. The commenter believed this would be problematic because conducting an evaluation in 2018 after the implementation of the program would be too late; the mercury accumulation would have already occurred and people would be exposed then on. In addition, EPA does not have a good "on time" track record.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

One commenter (OAR-2002-0056-3210) disputed EPA's rationale that the economics of a cap and trade program would lead to better control of bituminous coal sources since these sources emit more oxidized mercury and may deposit mercury locally. The commenter noted that EPA believes reducing oxidized mercury would reduce local hot spots. The commenter asserted that this rationale ignores current science on the atmospheric chemistry of mercury and the regional concentration component of the mercury deposition problem. The commenter submitted that uncontrolled sources of elemental mercury will continue to contribute to regional mercury deposition, especially in the summer during high ozone season. The commenter cited several studies and reports indicating that areas with elevated ozone levels can expect increased mercury deposition. The commenter concluded that mercury deposition is a year round local hot spot issue and a seasonal widespread regional deposition issue.

Similarly, one commenter (OAR-2002-0056-3437) submitted information confirming that mercury deposition of local waterbodies will continue as emissions actually increase under the lenient MACT limits or a cap and trade approach. While the commenter was generally supportive of a cap and trade approach , the commenter believed it must be designed to assure no hot spots. The commenter provided evidence from deposition monitoring that showed a correspondence between mercury deposition values and mercury emissions from sources within a 50 km radius; mercury deposition rates were highest at the monitor where nearby emissions were the highest. Given the concern about mercury deposition in the Great Lakes and the Grand Calumet watershed, the current mercury load in the region, and the potential for hot spots, the

commenter was very concerned about any approach that would allow emissions to increase above 1999 levels.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

5.4.1 Trading Constraints to Address Hot Spots

Comment:

Several commenters (OAR-2002-0056-2911, -3556) stated that mercury deposition is an issue that is global in scale and that U.S. EGUs represent about 1 percent of the global emissions. The commenters stated that EPA acknowledges that it cannot determine what the contribution of EGU mercury emissions is to concentrations in fish. The commenters further stated that EPA also acknowledges that it cannot determine how much the concentrations in fish will decrease, if at all, once EGU mercury emissions are reduced. The commenters noted that the concentration of mercury in fish is the pathway of exposure to humans. The commenters also pointed out that EPRI has submitted detailed comments addressing the issue of mercury "hot spots" and the lack of relevance to EGU mercury emissions. Consequently, the commenters could see no scientific justification to regional allocations and trading. In order to have a viable and robust trading program, the commenter 3556 believed it must be national in scope.

One commenter (OAR-2002-0056-4139) stated that any cap and trade program should be contained to a geographic area.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

One commenter (OAR-2002-0056-2064) opposed trading under CAA section 111 on a national scale. The commenter believes if trading is allowed under section 111, it should be limited to a regional or contiguous basis because of interstate deposition problems with mercury. Similarly, one commenter (OAR-2002-0056-3437) suggested that EPA should consider if geographic or other constraints on trading are needed to prevent hot spots. The commenter recommended establishing reduction targests to assure that all plants reduce emissions to some degree. The commenter submitted a cap and trade program must contain a backstop to ensure that no individual plant could emit more mercury than in 1999. The commenter believed the rule also must assure that states retain the ability to address local hot spots.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

Several commenters (OAR-2002-0056-3437, -3443) responded to EPA's request for comments on whether it would be appropriate to adjust the geographic scope of the trading program by introducing trading ratios to address regional differences. (See Fed. Reg. 4651, 4701.) One commenter (OAR-2002-0056-3437) understood that geographical constraints would be one possible approach to prevent hot spots. But the commenter believed this approach could add much complexity to the trading program and might not provide the desired result. The commenter stated a preferable approach would be a stringent limit to allocate allowances and the flexibility to impose more stringent local requirements. The commenter cautioned that EPA should be very clear about trading ratios so that industry will have clear direction to plan for compliance and states will be aware of any responsibilities that will be imposed on them.

One commenter (OAR-2002-0056-3443) did not support such adjustments to the geographic scope because they would hamper the effectiveness of the trading program by interfering with the market. More importantly, the commenter saw no need for such adjustments because EPA's analysis in the preamble leads to the conclusion that "hot spots" would not be a problem under a cap and trade program. (See 69 Fed. Reg. 4,651, 4,702-03.)

The commenter presumed that the main reason for making such geographic adjustments would be to address the potential for localized impacts. In regard to the issue of localized impacts, the commenter has been monitoring mercury in sediments and fish in the reservoirs on the Tennessee River and its tributaries for over 30 years. The commenter stated that these studies show that mercury levels in the sediment for both mainstream and tributary reservoirs in the entire Tennessee Valley region have declined substantially since 1973. Likewise, the commenter stated that although mercury levels in fish tissue in the reservoirs along the Tennessee River have varied, these levels indicate a constant or declining trend despite an increase in coal-fired generation on the commenter's system during this period. (The commenter attached a letter dated November 19, 2003, from the commenter to EPA on Mercury in Sediment and Fish in the TVA Reservoirs.) The commenter submitted that although the study identified areas with elevated mercury, none of these elevated levels were attributable to emissions from the commenter's coal-fired units. Rather, the elevated levels were the result of industrial activity, such as waste water discharges form the chlor-alkoli industry.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

One commenter (OAR-2002-0056-2247) stated that while they viewed a cap and trade program as the preferred policy approach, the cap must be lower and the trading properly constrained. The commenter suggested an additional control option. To insure reductions from western coal users and to prevent drift of emissions from eastern to western states, the commenter submitted that EPA should combine a lower cap with some form of a zonal trading plan that would achieve reductions in both the eastern and western areas of the U.S.

The commenter claimed that up to 90 percent of the mercury entering their waters comes from atmospheric sources outside the state. Their TMDL studies showed that a reduction in the range of 50 percent in atmospheric deposition would be needed to meet their projected water quality standard. EPA's deposition modeling predicted only a 5 percent reduction in certain areas of the state. The commenter believed the proposed cap of 15 tons is so loose that utility boilers in the commenter's state and those to the sourth and west would do little to control mercury emissions. The IPM modeling showed that utility boilers in the commenter's state and similar boilers west of the Mississippi burning Powder River Basis or lignite coal would reduce emissions by only 35 percent as a co-benefit of controlling SO_2 and NO_x. These states, including utilities in the commenter's state, are predicted to purchase credits from eastern utilities rather than control releases. Even the 5 percent reduction EPA predicted for the commenter's state may not occur because modeling did not account for banking or the cost-based safety valve. The commenter believed the 15 ton final cap would not address the commenter's problem–it seemed to shift the cost of SO_2 and NO_x controls at eastern boilers to western states burning PRB coal. Their analysis showed that tighter MACT standards or a lower cap are justified.

The commenter submitted that the drawback of a cap and trade program is that it reduces mercury where it is most cost effective, but does not address specific geographic needs. The commenter needs reductions from coal-fired plants to the south and west of the state. The commenter suggested trading zones with separate mercury caps and limiting trading between the zones. The commenter believed this would avoid relying on bituminous coal-fired boilers for nearly all the reductions.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

One commenter (OAR-2002-0056-2860) recommended a maximum allowable emission rate to address hot spots. The commenter asserted that EPA should provide options and support for identifying and mitigating potential hot spots.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

One commenter (OAR-2002-0056-1825) objected to a provision in the cap and trade program that would allow utilities in a State to avoid any additional mercury reduction even if studies confirm that hot spots are the result of emissions from local utilities.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

One commenter (OAR-2002-0056-3448) stated that delaying 70 percent of the emission reduction until about 2030 in the proposed CAA section 111 rule would perpetuate local and regional hot spots for 25 years and forever for the many areas affected by plants that will not install controls at all under a cap and trade system. The commenter believed proposals to adjust trading to attempt to address hot spots are likely to fail based on perceptions they would complicate and reduce the efficiency of a cap and trade program.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

One commenter (OAR-2002-0056-4139) stated that budgets need to be lowered to protect certain areas.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

One commenter (OAR-2002-0056-2173) stated that given the serious concern about hot spots, if EPA adopts a cap and trade approach, it must take all appropriate actions to ensure they do not result. The commenter recommended the following actions: (1) require excess "offsets"

(the offset ratio should be adjusted based on the ability of mercury reductions at one source to reduce deposition in the area of the other source to ensure that any reductions at units generating credits would have an equivalent environmental effect in the area of the unit purchasing the unit); (2) limit trades to a regional or basin-wide area; (3) limit amount of credits that can be purchased to meet limits; and (4) create a natural resources damage fund to compensate tribes, states, and other resource trustees for damage caused by hot spots by assessing a surcharge on credits that are traded.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

Several commenters (OAR-2002-0056-1671, -2108) stated that if EPA retains the cap-and-trade program, credits should be available only to plants that demonstrate through modeling that deposition is not occurring in local watersheds or land (i.e., hot spots).

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

One commenter (OAR-2002-0056-2160) suggested that maximum emission limits should be established for individual plants to avoid hot spots. The commenter noted that capping maximum emissions from a given plant has ample precedent in existing SO_2 and NO_x rules.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

Several commenters (OAR-2002-0056-2835, -2878) addressed the evaluation of control requirements after implementation of the cap-and-trade program. One commenter (OAR-2002-0056-2835) agreed with the EPA proposal to evaluate after the implementation of the control requirements in 2010 and 2018 whether the mercury cap adequately protects public health and, if necessary, take further regulatory actions to address any health risks not fully addressed by the cap-and-trade regulatory program.

The second commenter (OAR-2002-0056-2878) cited several scientific and policy concerns including lack of safeguards to protect the public health and secure additional needed reductions, toxicity of mercury and tendency to bioaccumulate in the food chain, potential for hot spots, and environmental justice. The commenter asserted that EPA's response to these concerns (reevaluate effects of cap and trade on local hot spots after implementation in 2018) would leave communities at risk for another 14 years or longer.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

Comment:

If EPA pursues regulation under CAA section 111, one commenter (OAR-2002-0056-2430) recommended that it include some type of risk and environmental health assessment including an evaluation of the effects of mercury deposition. The commenter noted that residual risk requirements under CAA section 112 address risk to public health and the environment, while CAA section 111 does not. The commenter asserts that the disassociation of CAA regulations from public health and the environment is unacceptable public policy and sets a bad precedent.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Effectiveness TSD.

5.5 APPLICABILITY

5.5.1 Affected Units

Comment:

One commenter (OAR-2002-0056-2862) stated the program threshold should be based on size of unit (m 25 MW). The commenter noted the current program threshold is consistent with the m 25 MW level set for EPA's Acid Rain program. The commenter believes this is an appropriate threshold. Including units based a size definition creates a fair and consistent regulatory program.

One commenter (OAR-2002-0056-2721) supported the proposed minimum level of generation of a fossil fuel fired combustion unit that serves a generator of 25 MW that produces electricity for sale would be affected by the proposed mercury regulations.

A second commenter (OAR-2002-0056-2913) stated the proposed CAA section 111 cap-and-trade provisions of the proposal expand upon the CAA section 112 definition of electric

utility steam generating unit by including combustion units less than 25 MW if they serve a generator greater than 25 MW. The commenter stated that CAA section 112 defines an electric utility steam generating unit as a 25 MW combustion units, but the proposed CAA section 111 cap-and-trade rule presumably would apply to combustion units, regardless of size, serving 25 MW generators (see 60.4104 (a)). It appeared to the commenter as though the Agency is attempting to expand the number of electric utility units to which this rule would apply beyond that authorized by statute. Furthermore, the potential exists for some electric utility units to be regulated by two different and conflicting regulations (i.e. the industrial/commercial/ institutional boilers and process heater MACT standards which are nearing final promulgation and these electric utility steam generating unit MACT standards). The commenter believed this is contrary to both statutory intent and expressed EPA policy. The commenter did not believe that this is the Agency's intent and this "inconsistency" between CAA section 112 definition and CAA section 111 applicability is merely an oversight on EPA's part.

The commenter recommended that, if the Agency ultimately decides that the best way to adopt a cap-and-trade rule is under CAA section 111, then this situation can be rectified in one of two ways: 1) Rewrite 40 CFR 60.4104(a) as applying to "Any fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale."; or 2) state, in the applicability section, that any unit covered in 40 CFR Part 63, Subpart DDDDD (i.e. the industrial/commercial/ institutional boilers and process heater MACT standards), is not covered under this subpart.

Response:

For purposes of model trading rule, an affected unit is defined as a coal-fire boiler or IGCC that serves a generator with nameplate capacity of more than 25 MWe producing electricity for sale (see regulatory text of final rule, §60.4104, for full definition). The definition also provides an exception for cogeneration units serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale (see regulatory text of final rule, §60.4104, for full definition).

As discussed in the final rule preamble (section IV.D.3), the approach of using a 25 MWe cut-off is consistent with existing SO_2 and NO_x cap-and-trade programs like the NO_x SIP call and the Acid Rain Program and the final Clean Air Interstate Rule. In addition, the Agency's historical interpretation of the subpart Da definition has been that a boiler meeting the capacity definition (i.e., greater than 250 million Btu/hr) but connected to an electrical generator with a generation capacity of 25 MWe or less would still be classified as an "electric utility steam generating unit" under subpart Da. EPA acknowledges that there are differences in definitions between the NSPS program and the Acid Rain and other trading programs (e.g., CAIR) that result from the underlying statutory mandates. From implementation standpoint, EPA maintains that is important for the applicability definition under the Hg modeling trading rule to be consistent with other cap-and-trade rules, especially the recently finalized CAIR.

Comment:

One commenter (OAR-2002-0056-2066) stated that combined heat and power (CHP) units currently represent only about 3 percent of the electric generating capacity covered by Agency's proposal. According to the commenter, CHP units are generally twice as efficient when compared to their utility counterparts, and about 2/3 of all CHP units burn natural gas and have extremely low NO_x emission rates. The commenter stated that while individual CHP emission rates will vary, the average gas-fired CHP emission rates are only 15-25 percent of that emitted by a typical utility. The commenter added that even CHP units using coal or oil as a fuel source are still much more efficient than a utility using the same fuels. The commenter further stated that CHP units are usually only a small part of a much larger industrial facility or complex. The commenter asserted that including these units into this rulemaking would layer another set of regulations on the entire facility, thus further complicating on-going compliance efforts. For these reasons, the commenter believed that CHP units should be exempted from inclusion in this rulemaking. According to the commenter, inclusion of traditional CHP facilities would provide negligible environment benefit while discouraging application of these ultra-efficient power and steam generators both now and in the future.

The commenter (OAR-2002-0056-2206) noted that EPA is proposing to establish a cap and trade program for regulated utility units that is similar to the current cap and trade for this sector under the Title IV program and the Agency's proposed rule relating to interstate air quality (69 FR 4652). The commenter further noted that as part of EPA's proposal, EPA would include some cogeneration units as electric utility units and make them subject to the rule. The commenter did not support this approach toward cogeneration units. Instead, the commenter suggested that EPA should exclude all cogeneration units. The commenter offered that EPA could include them in its planned study to see if unregulated units are causing adverse health effects.

Response:

As discussed in the final rule preamble (section IV.D.3), EPA believes it is important to include in the CAMR program all units, including congeration units, that are substantially in the business of selling electricity. As discussed above, the applicability definition under the Hg modeling trading rule is consistent with other cap-and-trade rules, especially the recently finalized CAIR.

Comment:

For CHP units, the commenter (OAR-2002-0056-3525) believed that EPA should define a "utility unit" as only those units that meet the definition on a net annual basis. The commenter pointed out that in the preamble, EPA, absent rationale, states that any CHP unit that meets the definition of a utility unit during any portion of the year would become subject to the rule. The commenter stated that requiring a CHP unit to stay below the utility unit definition on an instantaneous basis provides a disincentive for facilities to invest in new CHP capacity or to maximize the output and efficiency of their current CHP and energy-producing network of units.

The commenter encouraged EPA to confirm that for purposes of its proposed definitions of "EGU" and "cogeneration unit," all sales of electricity will be measured on a "net" basis, as is done in the acid rain program. The commenter stated that in determining that "net" basis, EPA's accounting should take account of the specific situation of major facilities with a number of cogeneration units. The commenter stated that at such plants, some units may be over the size threshold, while others may be below it. Yet, according to the commenter, the electricity from all those units will be pooled before it is either used in the plant or sold to the grid. In that case, the commenter believed EPA's accounting rules should provide for determining when the threshold conditions have been met by looking at all the electricity generated by all the cogeneration units, whether they were subject to the SIP call or not. The commenter asserted that no other approach would be administratively feasible.

The commenter stated an annual average should be used to determine whether cogeneration units sold more than one third of their potential electric output to the grid and more than 25 MW on a net annual average basis and thus were defined as EGUs. According to the commenter, a shorter averaging time could often result in classifying units as EGUs based on a short and unrepresentative operating history-for example, if power was generally used exclusively at the plant at which it was generated, but was sold to the grid when the production facility was down for maintenance.

The commenter pointed out in addition, in some cases, contractual arrangements may exist between the cogeneration facility and the local electric utility wherein all generated power is considered sold to the utility and all electricity used on the site is purchased from the utility. According to the commenter, in reality, only a small portion of the generated power really enters the grid from the cogeneration facility, and only that "net" sales of power should be considered when determining applicability with the EGU definition.

Subject to these qualifications, the commenter supported the cogeneration unit threshold being used for consideration as an EGU, specifically, a unit serving a generator with a nameplate capacity of >25 MW and supplying more than 1/3 of its potential electric output capacity and more than 25 MW to any utility power distribution system for sale. The commenter stated however, it would provide additional clarity and prevent confusion if it was specifically stated that units associated with generators of 25 MWe capacity or less were not affected sources under this subpart; and any cogeneration units not supplying both more than one-third of their potential electric output capacity and more than 25 MWe to any utility power distribution system for sale were not affected sources under this subpart. The commenter recommended that EPA include this additional clarifying language in the final rule.

Another commenter (OAR-2002-0056-2906) stated that for cogeneration units, EPA should define as an electric utility steam generating unit (utility unit) only those units that meet the definition of a utility unit on a net annualized basis. The commenter noted that in the preamble, EPA states that any cogeneration unit that meets the definition of a Utility Unit during any portion of the year would become subject to the rule (69 FR 4657). The commenter stated that EPA provides no rationale for this requirement. The commenter further stated that this

requirement stands in contrast to EPA's proposed CAIR, where the definition for a Utility Unit is based on a historical annual average (69 FR 4610).

The commenter stated that requiring a cogeneration unit to stay below the Utility Unit definition on an instantaneous basis would create a large disincentive for facilities to invest in new CHP capacity, or to maximize the output and efficiency of their current cogeneration and energy-producing network of units. According to the commenter, cogeneration units are inherently more efficient than traditional Utility Units (in many cases twice as efficient), and often provide distributed key power to the grid during transient or short-term periods of peak power demand. The commenter stated that in order to prevent being included within the Utility Unit definition, many cogeneration units will likely establish tight restrictions on exporting excess power to the grid, or eliminate export all together. According to the commenter, this would have the perverse effect of reduced cogeneration unit power output, reduced overall grid efficiency and reduced industrial steam and electricity generation efficiency.

The commenter stated that to prevent these undesirable consequences, and to prevent conflicts and confusion with the definition of a Utility Unit in the CAIR under which some of these units may choose to opt into the CAIR regulation, EPA should base the Utility Unit definition on a net annualized average and not "during any portion of the year."

Response:

As discussed in the final rule preamble (section IV.D.3), EPA confirms that, for purposes of applying the one-third potential electric output criteria in the CAMR program and the model cap-and-trade rules, the only electricity that counts as a sale is electricity produced by a unit that actually flows to a utility power distribution system from the unit. Electricity that is produced by the unit and used on-site by the electricity-consuming component of the facility will not count, including cogenerated electricity that is simultaneously purchased by the utility and sold back to such facility under purchase and sale agreements under the Public Utilities Regulatory Policy Act of 1978 (PURPA). However, electric purchases and sales that are not simultaneous will not be netted; the one-third potential electric output criteria will be applied on a gross basis, except for simultaneous purchase and sales. This is consistent with the approach taken in the Acid Rain Program.

Comment:

One commenter (OAR-2002-0056-2906) requested that EPA confirm that, for purposes of its proposed definitions of "Utility Unit" and "cogeneration unit," all sales of electricity will be measured on a "net" basis, as is done in the acid rain program. According to the commenter, in determining that "net" basis, EPA's accounting rules should take into account the specific situation of major facilities with a number of cogeneration units. The commenter pointed out that at such plants, some units may be over the size threshold for inclusion in the rule, while others may be below it. The commenter added that, yet, the electricity from all those units will be pooled together before it is either used in the plant, or sold to the grid. The commenter stated that, in other words, there will be no way to determine the particular use of the electricity

generated by the large units subject to the rule. The commenter believed that in that case, EPA's accounting rules should provide for determining when the threshold conditions have been met by looking at all the electricity generated by all the cogeneration units. According to the commenter, no other approach would be administratively feasible.

The commenter pointed out that in many cases contractual arrangements may exist between the cogeneration facility and the local electric utility wherein all generated power is considered sold to the utility and all electricity used on the site is purchased from the utility. According to the commenter, in reality, only a small portion of generated power really enters the grid from the cogeneration facility, and only that "net" sales of power should be considered when determining applicability with the Utility Unit definition.

The commenter stated that an annual average should be used to determine whether cogeneration units sold more than one third of their potential electric output to the grid and more than 25 MWe on a net annual average basis and thus were defined as Utility Units. According to the commenter, a shorter averaging time could often result in classifying units as Utility Units based on a short and unrepresentative operating history–for example, if power was generally used exclusively at the plant at which it was generated, but was sold to the grid when the production facility was down for maintenance.

Subject to these qualifications, the commenter supported the cogeneration unit threshold being used for consideration as an Utility Unit, specifically, a unit serving a generator with a nameplate capacity of greater than 25 MWe and supplying more than one-third of its potential electric output capacity and more than 25 MWe to any utility power distribution system for sale. The commenter stated that, however, it would provide additional clarity and prevent confusion if it was specifically stated that units associated with generators of 25 MWe capacity or less were not affected sources under this subpart; and any cogeneration units not supplying both more than one-third of their potential electric output capacity and more than 25 MWe to any utility power distribution system for sale were not affected sources under this subpart. The commenter recommended that EPA include this additional clarifying language in the final rule.

Response:

As discussed in the final rule preamble (section IV.D.3), EPA is finalizing to determine whether a unit is affected by the CAMR on an individual-unit basis. This unit-based approach is consistent with both the Acid Rain Program and the NO_x SIP Call. EPA considers this approach to be feasible based on experience from these existing programs, including for sources with multiple cogeneration units. EPA is unaware of any instances of cogeneration unit owners being unable to determine how to apply the one-third potential electric output capacity criteria where there are multiple cogeneration units at a source.

In a case where there are multiple cogeneration units with only one connection to a utility power distribution system, the electricity supplied to the utility distribution system can be apportioned among the units in order to apply the one-third potential electric output capacity criteria. A reasonable basis for such apportionment must be developed based on the particular

circumstances. The most accurate way of apportioning the electricity supplied to the utility power distribution system seems to be apportionment based on the amount of electricity produced by each unit during the relevant period of time.

The commenters concerns about "net sales" are addressed in the previous response.

Comment:

One commenter (OAR-2002-0056-3469) stated that the tribes support the EPA in their efforts to improve air quality. However, tribes needed protections to ensure their future energy projects and the economic benefits derived from current mining operations are not jeopardized. The tribes supported the exemption of all new power plants developed by the tribes or developed on tribal land from being required to hold allowances for SO_2, NO_x or mercury emissions, as long as these new power plants meet New Source Performance Standards (NSPS) and all other relevant permitting requirements at the date of initial operation. These power plants would adhere to the monitoring requirements specified in the rules ensuring that these NSPS requirements are met over time.

Comment: One commenter (OAR-2002-0056-2850) supported exemption of new units from the Hg program that are constructed with Best Available Control Technology for Hg. The commenter stated that if a new unit exemption is not implemented, credits should be purchased from the new Hg allowance market or buyout mechanism.

Response:

In the final CAMR, new sources will be covered under the Hg cap of the trading program, and will be required to hold allowances equal to their emissions. EPA maintains that is essential to include new sources under the cap to ensure that environmental goal of reducing mercury emission is achieved. With new sources under the cap, the environmental goal continues to be achieved despite future growth in the electric power sector, as older coal-fired generation is retired and replaced new coal-fired generation.

Comment:

One commenter (OAR-2002-0056-2162) stated that waste coal-fired plants should not be subject to the proposed mercury rules.

Response:

As discussed in the final rule preamble (section IV.D.3), EPA points out that coal refuse is already subject to other Utility Unit programs, such as the Acid Rain program, the NSPS program (40 CFR part 60, subpart Da), and the CAIR program. Consequently, EPA rejects the commenter's request to not be included in the CAMR program.

5.5.2 25 lb Exclusion

Comment:

Several commenters (OAR-2002-0056-2161, -2267, -2375, -2634, -2830, -2913, -2922, -2948) supported the provision excluding units that emit less than 25 pounds of mercury per year from the cap-and-trade program.

One commenter (OAR-2002-0056-2161) suggested that EPA require these emitters to conduct compliance testing annually to verify the level of their emissions and report the results to EPA. As a result EPA would be able to monitor the national emissions profile of this group of sources and change the way they participate in the mercury cap and trade program if their emissions profile changes significantly.

One commenter (OAR-2002-0056-2267) requested that EPA consider extending the exemption to the Phase I cap as well. The commenter stated that controls on low emitting units are not highly cost-effective. EPA has acknowledged that expected new mercury-specific control technologies may not practically apply to these units. Moreover, emissions from such units do not contribute significantly to over-all mercury emissions. The commenter noted that EPA's data indicates that these units (numbered at 396) currently account for less than 5 percent of total mercury emissions. The commenter believed EPA should exclude these units because the cost-savings would be substantial for such units without affecting the ability to achieve the proposed caps. In the event low emitting units are excluded from the Phase I and/or II cap, the commenter would support provisions that would allow such units (as well as non-affected units) to opt-in to the cap-and-trade program at their discretion as in the NO_x Budget Trading Program.

One commenter (OAR-2002-0056-2375) stated that EPA has authority to promulgate such an exemption based on its inherent de minimis authority. The commenter noted sources of emissions below this level comprise less than 4 percent of current U.S. power plant emissions. The commenter believed exempting them from the rule would not jeopardize the caps. The commenter stated that moreover, the exemption is warranted because pollution controls required for Phase II may not be feasible for sources with low emissions.

Several commenters (OAR-2002-0056-2634, -2922, -2948) added that since these units do not significantly contribute to total domestic emissions, the 2010 and 2018 caps should remain unchanged and be applicable to the units remaining in the program, even if these sources are excluded from the program.

One commenter (OAR-2002-0056-2914) stated that requiring low emitting units to participate in the proposed cap-and-trade program would provide very little benefit in comparison to the costs needed to become effective trading partners. The commenter also stated that low emitting units, especially those already equipped with MACT standard setting technology should only be required to demonstrate that the installed pollution controls are operating properly, monitor operating parameters and emissions, keep records of their operating

parameters and emissions, report their emissions, and nothing more. The commenter submitted suggested regulatory language to implement and exemption for low emitting units.

One commenter (OAR-2002-0056-2560) supported the exclusion of coal-fired electric generating units (EGUs) that emit less than 25 pounds of mercury per year. According to the commenter, these units account for a very small proportion of mercury emissions.

One commenter (OAR-2002-0056-2883) urged the EPA to consider the implications of both proposed rules on smaller emitters and urges the EPA to provide a de minimus exemption from the rule for de minimus emitters.

One commenter (OAR-2002-0056-3445) noted that EPA has expressed concern about units with low mercury emissions rates (e.g., less than 25 pounds/year) and has asked for comment on excluding these units (69 FR 4999). The commenter believed EPA should exclude these units. The commenter stated that excluding them will provide an incentive to reduce emissions to below the 25-pound/year level through pollution prevention or innovative technology. The commenter believed that this clearly is an environmental benefit. The commenter further suggested that if the agency excludes these units in a cap-and-trade program, the overall mercury emissions cap should not be reduced by the amounts that these sources emit (i.e., the 2018 cap should remain 15 tons even if these sources are excluded from the program).

One commenter (OAR-2002-0056-2891) stated that EPA should include an exclusion–or at a minimum, reduced requirements–for small emitting units where additional emission controls cannot be economically justified. The commenter believed equipping smaller units with state of the art emission controls is not economically viable and equipping larger units that already emit relatively small amounts of mercury is not cost effective. According to the commenter, excluding these units from any additional mercury controls, or phasing in requirements for these units would be more cost effective while not resulting in any significant detriment to mercury reduction goals.

One commenter (OAR-2002-0056-2867) supported exempting units with mercury emissions less than 25 pounds per year. The commenter recommended, however, that EPA should re-allocate the allowances to controlled units in proportion to their annual heat input. If these allowances are reallocated, the commenter believed it would be incumbent on these exempted, low-emitting units to monitor emissions using infrequent measurement methods.

One commenter (OAR-2002-0056-3445) noted that EPA has expressed concern about units with low mercury emissions rates (e.g., less than 25 pounds/year) and has asked for comment on excluding these units (69 FR 4999). The commenter believed EPA should exclude these units. The commenter stated that excluding them will provide an incentive to reduce emissions to below the 25-pound/year level through pollution prevention or innovative technology. The commenter believed that this clearly is an environmental benefit. The commenter further suggested that if the agency excludes these units in a cap-and-trade program, the overall mercury emissions cap should not be reduced by the amounts that these sources emit (i.e., the 2018 cap should remain 15 tons even if these sources are excluded from the program).

One commenter (OAR-2002-0056-2172) strongly supported exempting from the final rule those units that emit less than 25 lbs. of mercury per year. The commenter believed that EPA has ample legal authority to provide such an exemption, which would provide important regulatory relief for small units that may not be able to comply, particularly with the Phase II cap.

One commenter (OAR-2002-0056-2850) supported a proposal to exempt units whose mercury emissions are under 25 pounds per year. The commenter added that would involve less than a 10 percent shift in the tonnage cap but would exclude coal units for which mercury control retrofit would be the least cost effective.

Response:

As discussed in the final rule preamble (section IV.D.3.iv), the low-emitter exclusion was proposed to address small business entities. Small business entities, however, are not necessarily small emission emitters. Of the 396 units with estimated Hg emissions under 25 lb in 1999, most (about 95 percent) are not owned by small entities and a significant amount (about 10 percent) are large-capacity units (greater than 250 MW). In addition, removing low-emitters from the trading program could increase costs, because a significant amount of the 396 units are large-capacity units that might be expected to be net seller of allowances because they are already achieving emission reductions. Therefore, EPA maintains that the low-emitter exclusion may not be the best way to address small entity burden. For today's final CAMR, EPA is not finalizing a low-emitter exclusion and EPA recommends States address small business entities through the allocation process. For example, States could provide a minimum Phase II allocation for small entities (e.g., allocation based on projected 2010 unit emissions). EPA also maintains that the cap-and-trade program and other program aspects minimize the burden for small business entities. These program aspects include the 25 MWe size cut-off.

Comment:

Several commenters (OAR-2002-0056-2260, -2365, -2661, -2891) believed EPA should include an exclusion–or at a minimum, reduced requirements–for small emitting units where additional emission controls cannot be economically justified. The commenters stated equipping smaller units with state of the art emission controls is not economically viable and equipping larger units that already emit relatively small amounts of mercury is not cost effective. The commenters added that excluding these units from any additional mercury controls, or phasing requirements for these units would be more cost effective and not detrimental to mercury reduction goals.

One commenter (OAR-2002-0056-2267) believed that EPA must limit the disproportionate impact of the proposed rules on low emitting units. The commenter noted the low emitting units emit relatively smaller amounts of emissions and controls on such units are less cost-effective than for larger units. The commenter stated imposing controls on the low emitting units will not significantly contribute to reductions required to meet the proposed caps or to the overall reductions achieved under the MACT approach if it is adopted. The commenter

stated that for these reasons, EPA should provide appropriate relief for the low emitting units under the proposed cap-and trade or MACT programs.

One commenter (OAR-2002-0056-3514) supported EPA's conclusion that the control technologies currently being researched will not be practical at units emitting less than 25 tons per year, and suggested that exemption apply regardless of which implementation option EPA selects for the final rule.

One commenter (OAR-2002-0056-1969) stated that EPA is correct in its concern that new, mercury specific control technologies that are expected to be developed prior to the Phase II cap deadline may not practicably apply to units with low annual mercury emissions. The commenter suggested that electric generating units emitting less than 25 pounds per year be excluded from the Phase II cap.

Response:

As discussed above and in the final rule preamble (section IV.D.3.iv), EPA is not finalizing a low-emitter exclusion and EPA recommends States address small business entities through the allocation process.

Comment:

One commenter (OAR-2002-0056-3437) stated that the 25 lb/yr exemption should not be included. The commenter noted that in the SNPR, the applicability is limited to EGU greater than 25 MW with no low-emitting exception. The only exception is for retired units.

One commenter (OAR-2002-0056-3459) stated in public interest group comprehensive comments that if EPA proceeds with its illegal trading program, it must reject program elements that permit increased pollution. In response to EPA's request for comments, the commenter stated utility units emitting less than 25 pounds of mercury should not be exempted from the 2018 cap. The commenter asserted that the record documents the origin of this provision and shows that EPA did no analysis of impacts or costs. The commenter stated that the language comes directly from the Small Business Administration (SBA), which is concerned about small units having difficulty making the reductions, but EPA offers no evidence that this is true. The commenter stated that EPA's memo identifying such units indicates that only about 60 (of 396) are standalone units; all others are boilers part of a multi-boiler facility where boilers are likely tied into a common ductwork for pollution control. The commenter added that because EPA is proposing to allow facilities to bubble their emissions, units other than the one or two small units can be controlled to a greater extent to compensate for the lower emitting small units. The commenter stated that his would help mitigate any concerns about control costs for small units. Thus, the commenter asserted that the proposal to exempt them is arbitrary and capricious.

Response:

As discussed above and in the final rule preamble (section IV.D.3.iv), EPA is not finalizing a low-emitter exclusion and EPA recommends States address small business entities through the allocation process.

Comment:

One commenter (OAR-2002-0056-2911) recommended that EPA follow its concerns about the ability of smaller units to implement mercury-specific control technologies. The commenter recommended that units emitting less than 50 pounds of mercury per year be exempt from mercury-specific control requirements.

One commenter (OAR-2002-0056-3556) recommended that EPA follow its concerns about the ability of smaller units to implement mercury-specific control technologies. The commenter recommended that units emitting less than 50 pounds of mercury per year be exempt from mercury-specific control requirements.

One commenter (OAR-2002-0056-3556) recommended that EPA follow its concerns about the ability of smaller units to implement mercury-specific control technologies. The commenter recommended that units emitting less than 50 pounds of mercury per year be exempt from mercury-specific control requirements.

One commenter (OAR-2002-0056-3556) recommended that EPA follow its concerns about the ability of smaller units to implement mercury-specific control technologies. The commenter recommended that units emitting less than 50 pounds of mercury per year be exempt from mercury-specific control requirements.

One commenter (OAR-2002-0056-3432) stated that like other small rural electric generating and transmission (G & T) cooperatives, they have a number of small coal-fired boilers. The commenter stated that installing and operating emission controls on small units is not economically viable, and the amount of mercury emissions attributable to these small units is not significant. The commenter supported exempting units with mercury emissions less than 50 pounds/year from the control program and re-allocating the exempt unit allowances to units in the program in proportion to their annual heat input. The commenter acknowledged that exempted units would need to demonstrate that their emissions do not rise above the exempted level, however, less sophisticated and cost-effective monitoring methods should be allowed.

One commenter (OAR-2002-0056-2422) noted that EPA has requested comment on the basis for excluding certain small coal-fired units from emission controls in the context of an emission trading program. The commenter encouraged EPA to exclude at least these 396 small units emitting less than 25 pounds of mercury annually due to the lack of cost-effective mercury controls available for retrofit installations, and the likelihood that emissions from these units are not contributing measurably to any domestic public health problems. According to the commenter, indeed, a higher cutoff limit for a small unit exclusion could be justified for the

reasons that EPA has identified regarding the prospective retrofit of mercury control technologies in a Phase II trading program. For these reasons, the commenter urged EPA to establish a minimum emission threshold for exclusion that will avoid the need to control emissions at small electric generating units whose emissions do not measurably impact global mercury budgets. According to the commenter, if confronted with plant- or unit-specific emission limits, such units likely would be retired rather than retrofitted with costly control technologies.

Response:

As discussed above and in the final rule preamble (section IV.D.3.iv), EPA is not finalizing a low-emitter exclusion and EPA recommends States address small business entities through the allocation process.

Comment:

One commenter (OAR-2002-0056-2861) stated that EPA has asked for comment on excluding units that emit less than 25 pounds of mercury per year from the Phase II mercury cap. According to the commenter, as noted, these units make up a small percentage of the total mercury emissions from U.S. coal-fired power plants (5 percent by EPA's estimate). The commenter believed an exclusion for low emitting units is appropriate, both for all phases of a cap and trade program and for a MACT program. However, rather than exclude units based on their mercury emissions as EPA has proposed, the commenter recommended the exclusion be based on a unit's size, with a cutoff in the range of 100 to 140 MW. The commenter believed a MW size cutoff would provide a more definite exclusion than use of mercury emissions. The commenter stated that currently, there is great uncertainty and variability in estimations of mercury emissions from power plants. The commenter submitted that specifying unit size as the parameter for determining the exclusion will provide greater regulatory certainty and will meet similar objectives as EPA identified for considering a 25-pound exclusion.

The commenter has reviewed the estimated mercury emissions from the commenter's coal-fired power plants for 2002 based on information provided in their annual TRI report. The commenter operates 31 coal-fired boilers burning Eastern bituminous coal. These boilers range in size from 38 to 1120 MW. For 2002, the 13 boilers of 100 MW or less in size accounted for only 5 percent of the commenter's estimated coal-fired boiler mercury emissions, and each of those boilers had calculated emissions less than 25 pounds. The commenter suggested a broader analysis of all power plants in the nation may show that a unit rating as high as 140 MW would account for 5 percent or less of total mercury emissions. According to the commenter, as suggested in EPA's proposal, the cost of emissions monitoring and administration for these units with low emissions is excessive and would result in very little actual reduction in emissions. The commenter added that requiring sources to incur the cost of monitoring simply to demonstrate that they qualify for the exclusion when there is a surrogate metric, megawatts, which will yield very similar results is not cost effective and is not good public policy.

The commenter stated that if EPA does exclude low emitting units under a cap and trade program, the cap for the remaining, non-excluded units should not be reduced to offset the emissions from the excluded units. The commenter noted that the proposed 15 ton cap on mercury has no specific regulatory or scientific basis and therefore EPA is not required to offset the insignificant amount of emissions from small sources as if there were a "hard cap" on the allowable mercury emissions. The commenter submitted that reducing the 15 ton cap would simply shift an additional burden onto the regulated units, and would tend to drive up the cost of allowances by locking up 5 percent of the total allowances that would otherwise be available for trading.

The commenter noted that in its MACT proposal, EPA proposed that low-emitting units be excluded only from monitoring requirements for low-emitting units. Consistent with their position on the cap and trade program, the commenter believed these low-emitting units (units rated below a specified MW rating as they have proposed, or units below 25 pounds of mercury as EPA has proposed) should be excluded from all MACT requirements.

Response:

As discussed above and in the final rule preamble (section IV.D.3.iv), EPA is not finalizing a low-emitter exclusion and EPA recommends States address small business entities through the allocation process. The CAMR cap-and-trade program includes a 25 MWe size cut-off which EPA believes is appropriate.

Comment:

One commenter (OAR-2002-0056-2661) proposed that smaller emitting units be allowed to be bubble with other larger sources within the larger system-wide average for a utility or group of utilities. The commenter believed that greater emission controls would be realized at large emitting units and make control schemes more cost effective to implement.

Response:

As discussed above and in the final rule preamble (section IV.D.3.iv), EPA is not finalizing a low-emitter exclusion and EPA recommends States address small business entities through the allocation process. EPA also notes that the cap-and-trae program allows for the commenter's proposal.

Comment:

One commenter (OAR-2002-0056-3509) stated that to the extent that the final Utility Mercury Rule does require controls of small municipal generators via allowance trading or other requirements, EPA should provide these units with other compliance flexibility options to reduce the cost of such compliance.

One commenter (OAR-2002-0056-3509) strongly urged the EPA to exclude the smallest emitting units (units with less than 25 pounds annual emissions) from mercury controls under either the MACT or the cap-and-trade approach, because these small units emit a relatively insignificant level of mercury; because these units will suffer drastic, disproportionate and costly impacts from the rule; because the technology to comply is unproven for these small units; and because the continued operation of these units is critical to the basic energy needs of local communities in Michigan. The commenter urged EPA to adopt this exclusion for small emitters for both existing affected units and new affected units, including those that blend coal and non-coal fuels in their generation mix (and who measure emissions using EPA's suggested mass balancing approach).

One commenter (OAR-2002-0056-3509) stated that the rule's requirements for utility unit mercury controls, under either the MACT or trading approach, will disproportionately impact the smallest units and systems. Based on information derived from EPA's Mercury Information Collection Request, Toxic Release Inventory reporting, and stack testing for mercury emissions, the commenter estimated that the units they own and operate are emitting less than 25 pounds of mercury annually each. The commenter stated this places them in the category of units that EPA refers to as "small emitters." The commenter pointed out that it is important that the Utility Mercury Rule considers and helps mitigate small entity impacts for several economic and environmental reasons, including:

- Diseconomies of Scale–The capital costs for emissions control at small-sized utility units is disproportionately high due to inefficiencies in mercury removal, space constraints for control technology retrofits, and the fact that small units have fewer rate base customers upon which to spread these costs.

- Less Bang for the Buck–The commenter stated that as EPA has acknowledged, smaller utility units contribute a relatively insignificant level of mercury in the context of the industry-wide contribution of mercury emissions.

- Unproven Technologies–The commenter was not able to provide any technical information on whether these small units could reduce mercury emissions to the low levels proposed by the EPA either under the MACT approach or the cap-and-trade approach–because mercury control technologies are generally untested and unproven for these sizes and types of units. The commenter emphasized EPA's own recognition that "the new, mercury-specific control technologies that we expect to be developed prior to the [2018] Phase II cap deadline may not practicably apply to such units period." Proposed Rule at 4699. The commenter also noted that the current DOE/EPRI/EPA effort to test the availability and effectiveness of mercury control technologies for coal-fired utility units involves primarily larger-sized units (See http://www.netl.doe.gov/coalpower/environment/). The commenter added that nor do these DOE demonstration studies, or other available studies, show whether mercury control technologies are effective, let alone cost-effective, at the smallest sized coal-fired units. To the commenter's knowledge, no large scale field testing for activated carbon

technology have been conducted for units <80 MW. The commenter added that these technologies are untested for the smallest utility units.

- More Limited Access to Capital–Smaller utility systems generally have less capital to invest in pollution control than larger, investor-owned systems, due to statutory inability to borrow from the private capital markets, statutory debt ceilings, limited bonding capacity, borrowing limitations related to fiscal strain posed by other, non-environmental factors, and other limitations.

- Limited Ability to Average Emissions–Public power systems have much less flexibility in trading under the proposed Utility Mercury Rule because municipalities typically do not own multiple utility units that can utilize system-wide averaging of emissions for cap-and-trade compliance purposes. Likewise, the commenter did not own units that are large enough to enable the application of control technology that could likely produce mercury trading credits.

- Important Role of Public Power to Communities–Michigan public power communities play an important role in the competitive utility industry, and provide valuable services to local citizens. Pollution controls should not disproportionately impact smaller entities and thereby impose a competitive disadvantage on municipalities.

The commenter stated that for all these reasons, EPA should take into account the disproportionate adverse impacts of the Utility Mercury Rule on small systems and units. Moreover, the commenter emphasized that the ability of these small electric systems to purchase mercury allowances on the market is not a sufficient solution, by itself, to the major economic challenges that will face these communities under the Utility Mercury Rule. The commenter stated that there are substantial transaction costs to allowance trading, as recognized by the D.C. Circuit Court of Appeals. See Michigan v. EPA, 213 F.3d 663, 676 and n.3 (D.C. Cir. 2000) ("A glance at EPA's regulations for allowance trading will convince any doubter that transaction costs can safely be expected to be substantial.") The commenter further stated that in addition, the Utility Mercury Rule's trading market may never generate sufficient excess allowances to alleviate any of this burden on small electric systems and units. The commenter believed that without consideration of the particular challenges and needs of small electric units, the long-term economic viability of these systems will be subject to the vagaries of an uncertain and potentially scarce allowance market.

One commenter (OAR-2002-0056-3509) encouraged EPA to consider allowing small municipal generators (with capacities of less than 25 megawatts) that are located at a common facility with larger units (>25MW), to have the voluntary option to "opt-in" the smaller, less than 25 MW units, to the Utility Mercury Rule. The commenter added that most importantly, EPA should provide options for mercury compliance optimization at electric generating facilities where there are units that are considered Industrial Boiler MACT units that are operated in common with proposed Utility Mercury Rule units. The commenter added that the current situation is particularly difficult for those public power systems, like some of those commenting here, who have both >25MW and <25MW electric generating units located in a common facility.

The commenter noted that in one case, these different sized units are located on a common steam header. The commenter stated that however, under EPA's Industrial Boiler MACT and proposed Utility Mercury Rule, these systems will be unable to average emissions facility-wide, or enjoy the compliance optimization and flexibility necessary to be able to comply cost-effectively.

The commenter noted that EPA specifically requests comments in the Proposed Rule (4657) on how to consider units subject to different EPA mercury rules at the same facility. The commenter emphasized that this is a problem, and encourages EPA to allow small, <25MW EGUs located at a common, contiguous facility with other EGUs subject to the Utility Mercury Rule, to be able to opt-in to the Utility Mercury Rule, either to claim the "small emitter" exclusion, or to be able to average and trade allowances among their common units.

Response:

As discussed above and in the final rule preamble (section IV.D.3.iv), EPA is not finalizing a low-emitter exclusion and EPA recommends States address small business entities through the allocation process.

Comment: One commenter (OAR-2002-0056-4456) supported a small emitter exemption that would apply to either a cap/trade-based or MACT -based Hg emissions regulatory system. However, the commenters suggested that EPA can best achieve its objectives by crafting an exemption that is facility or source based, as opposed to one that is solely unit based.

The commenters stated that EPA's notice styles the proposed small emitter exemption as one applying on a unit basis. The commenters stated that, however, EPA's data shows that creating a unit-based Hg exemption does not isolate a class of small utility emitters. The commenters noted that many units covered by EPA's suggested unit-based exemption are smaller units at very large multiple-unit electric generating facilities. The commenters stated that, conversely, EPA's data shows that many units that may emit more than 25 pounds of Hg per year are single units at small electric generating facilities. According to the commenters, thus, a unit-based proposal does not correctly identify the universe of small utility Hg emitters.

The commenters proposed that EPA adopt a final rule that exempts from Hg regulation all utility units at common-source plant facilities that emit, on a facility-wide basis, less than a threshold amount of Hg per year. For the threshold amount, the commenters suggested that EPA convert the Clear Skies unit-based exemption (50 pounds or less per unit) to a facility-based exemption so that the total projected exempt emissions (6.9 percent of the total) remains the same. The commenters stated that EPA's 1999 ICR plant emission data base shows this cut-off, on a facility basis, is approximately 95 pounds (or less) of Hg facility emissions per year.

According to the commenters, alternatively, EPA could convert the 25 pound unit-based exemption referenced in EPA's Notice to a facility-based exemption so that the total exempt emissions (3.9 percent of the total) remains the same. The commenters stated that EPA's 1999 ICR plant emission data base shows this cut-off, on a facility basis, is approximately 62 pounds (or less) of Hg facility emissions per year.

The commenters suggested EPA adopt the following procedures to implement a facility-based small emitter exemption:

- Initial Identification of Exempt Facilities. EPA would identify potentially qualifying facilities (i.e., all utility units at facilities emitting less than the annual utility facility Hg threshold) from its 1999 ICR plant data base.

- Utility Election. Owners of qualifying facilities identified by EPA could, at their election, have units at their facilities designated as exempt or, in the alternative, designated as non-exempt covered utility units.

- Post-Election Actions. Under cap and trade, qualifying units that a facility owner elects for exempt status would receive no allowance allocations. Consistent with the approach taken in the Chairman's Mark bill, remaining affected units would be allocated allowances (e.g., if a 15 ton Phase II Hg cap is in place, allowances equal to 15 Hg tons would be allocated to non-exempt affected units). (See, S. 1844, §§471,473). Under MACT, qualifying units that a utility elects for exempt status would initially be exempt from MACT Hg regulations.

- Monitoring. Facility owners electing exempt status would be required to monitor their facility Hg emissions in a cost-effective manner. Hastings and Grand Island suggest that exempt facilities utilize EPA-approved ASTM Hg sampling and Hg emission testing procedures at frequencies selected by facility owners, but no less than quarterly. Annual Hg emissions would be calculated from this data, using the same procedures EPA utilized to estimate the unit-specific 1999 Hg emissions referenced in its Notice (49 F.R. at 4699).
- Excess Emissions. If an exempt facility exceeded the exemption Hg emission threshold in any year, the facility owner, under the cap-and-trade proposal, would have to obtain Hg allowances equal to its excess emissions (Hg emitted (pounds) threshold Hg amount (pounds) = excess Hg emissions). Under MACT, the facility owners could pay an appropriate fine, or if the problem became a persistent one, the facility would lose its exempt status and become subject to the applicable governing MACT standards for non-exempt units.

- New Units. Any new utility units built at exempt facilities would be subject to otherwise applicable Hg emission regulations, but pre-existing facility units would remain exempt if the exemption threshold is not exceeded for the pre-existing facility units.

Both EPA and Congress have expressed concerns about small Hg emitters. These concerns are driven by the huge costs that Hg controls will impose on impacted utilities and the cost/benefit considerations of imposing these huge costs on very small Hg emitters. The commenters suggested that the correct cost/benefit calculus results in exempting facilities, many of which are publicly-owned or co-ops, where overall facility emissions are low. According to the commenters, EPA can achieve its national Hg reduction objectives without subjecting

facilities that contribute only a tiny fraction of national Hg emissions to extraordinarily expensive regulations.

Response:

As discussed above and in the final rule preamble (section IV.D.3.iv), EPA is not finalizing a low-emitter exclusion and EPA recommends States address small business entities through the allocation process.

Comment:

One commenter (OAR-2002-0056-2162) supported the promulgation of an exemption from the proposed mercury rules for electric utility steam generating units emitting less than 25 pounds of mercury per year.

The commenter noted that in its preambles to the Proposed Mercury Rules, the Agency solicits comment on a proposed exemption from the Phase II requirements of the proposed mercury cap-and-trade rule for units emitting less than 25 pounds of mercury per year. The commenter noted that the Agency's basis for the proposed exemption from the requirements is that low emitting sources would be disproportionately impacted by the costs of complying with requirements under the proposed MACT standard. The commenter stated that the available information clearly justifies this concern. According to the commenter, while the Agency estimates that 396 of the 1,124 units operational in 1999 (35.4 percent of total operating units) would meet the 25 pound exemption, these units in the aggregate would contribute less than 5 percent of total mercury emissions. The commenter added that, further, according to the Agency's data, exemption of these units from the Phase II cap would not interfere with the overall ability of affected sources to comply with the 15 ton cap. The commenter stated that, accordingly, proposed 25 lb/year exemption, a substantial number of sources would be forced to absorb significant expense without achieving any appreciable environmental benefit.

The commenter stated that, likewise, the Agency expressed concern that the mercury specific control technologies currently under development may not apply to low-emitting units, and therefore those units would be unable to further reduce mercury emissions in accordance with cap-and-trade requirements. The commenter stated that with respect to their facilities, the units already are subjected to the best commercially available mercury control technology. According to the commenter, these low emitting sources could not reasonably further reduce mercury emissions in response to any cap-and-trade or other mercury control regulation.

In addition to its position that waste coal-fired sources should be exempt from the Proposed Mercury Rules, the commenter also supported the proposed exemption of sources emitting less than 25 pounds of mercury per year from the Proposed Mercury Rules, for the reasons articulated by the Agency in its preamble. The commenter believed that the de minimis nature of these sources supports the implementation of a wholesale exemption from the proposed MACT-based emission limitations or the proposed cap-and-trade program, whichever is finally promulgated by the Agency. The commenter stated that, specifically, the Agency's rationale for

exempting such sources from the Phase II mercury cap-and-trade program also would support an exemption from MACT requirements. According to the commenter, to the extent that low emitting sources would be unable to further control mercury emissions as required under the Phase II cap due to the unavailability of effective add-on mercury controls, such sources likewise would be unable to meet the proposed MACT standards. The commenter further stated that the regulation of such low emitting sources would be inconsistent with the Agency's mandate to consider the necessity and benefit of regulation for specific affected sources.

According to the commenter, to the extent that the Agency does promulgate an exemption for sources emitting less than 25 pounds per year of mercury, the exemption should be absolute, and should not result in the imposition of monitoring, testing or record keeping requirements upon these de minimis sources. The commenter stated that such an approach would be consistent with other MACT standards developed by the Agency, pursuant to which certain de minimis sources within a regulated source category may be completely exempted from all requirements of the relevant MACT regulation.

Response:

As discussed above and in the final rule preamble (section IV.D.3.iv), EPA is not finalizing a low-emitter exclusion and EPA recommends States address small business entities through the allocation process.

5.5.3 Opt-ins

Comment:

Several commenters (OAR-2002-0056-2900, -3432, -2105) supported allowing facilities with both industrial boiler units and coal-fired utility units to opt the industrial boiler units into the electric utility rule for purposes of meeting the emissions standard. The commenter believes a final rule should allow affected facilities with both industrial boilers and coal-fired utility units the compliance flexibility to meet one Hg emission limit through facility-wide emissions averaging.

One commenter (OAR-2002-0056-2105) recommended that any emission-trading program for Utility Steam Generating Units be promulgated with an "opt-in" provision so that other sources and industries with verifiable and surplus mercury emission reductions could generate and trade them as viable emission reduction credits under this rulemaking. The commenter was aware of the many obstacles and potential legal challenges, however in this instance, the commenter felt it was imperative that more, faster, and cost-effective reductions are made as soon as practicable. The commenter believed that providing an "opt-in" provision for any and all sources would encourage the maximum reduction in emissions in the shortest amount of time, in the most cost effective manner and with the least amount of social cost in the form of elevated energy costs to the public. A second commenter (OAR-2002-0056-1756) asked if the rule will allow other types of sources (non-utility combustion or non-combustion mercury) to participate in trading or offsets in cap and trade program?

One commenter (OAR-2002-0056-3432) believed that if, in the final rule, the EPA does not allow sources to opt-in industrial boiler (IB) unit(s) into the Utility Mercury MACT, or if the final rule does allow the flexibility of opt-in and sources choose not to opt-in IB unit(s) due to their own unique situations, these sources should not be faced with expensive additional monitoring or apportionment methods for the determination of the contribution of mercury emissions from IB unit(s). For those sources with the "common stack" situation, the commenter stated that the EPA should allow the source the flexibility to monitor the mercury concentration in the common stack and to apply this concentration to the IB(s) flue gas duct. According to the commenter, utilizing the EPA approved volumetric flow measurements for the common stack and for the IB(s) flue gas duct, the source would then be able to calculate mercury mass emissions for the common stack and for the IB(s) duct. With these parameters, electric utility steam generating units (EUSGU) and IB(s) mercury mass emissions can be determined by simple subtraction.

Response:

Under the final CAMR, EPA is requiring States and Tribes to meet emissions budgets and to achieve those emissions reductions from coal-fired power generation sources. EPA is not allowing States or Tribes to opt-in other sources into the cap-and-trade program to meet its emission budget. EPA feels strongly that any cap and trade program needs to have strong monitoring and reporting requirements, which are difficult to enforce and implement for other source categories. Given that other stationary sources (e.g., boilers) are already complying with MACT Hg standards, cost-effective reductions from other source categories are not likely.

To address the issues associated with monitoring units at a common stack where one is affected and the other not EPA provides alternative monitoring methodology. This alternatives can possibly include: measuring Hg for the affected unit in the duct; doing a proportional distribution based on fuel; using a conservative mass balance to determine the proportion of Hg in the flue gas that each unit is contributing.

Comment:

Commenter (OAR-2002-0056-3530, -2833) stated that the utility mercury reductions rule (UMRR) should not extend its mandates to either current or future combined-heat-and-power systems (CHP). The commenter stated that in virtually all cases, CHP units are a source of highly efficient power with correspondingly low emissions. The commenter added that hundreds of industrial facilities depend on the economic efficiencies of CHP. The commenter stated that in fact, the President's National Energy Policy recommends the increased use of CHP systems to improve energy efficiency and decrease air emissions. The commenter also stated that however, industrial units should be given the opportunity to voluntarily opt-in to the benefits of the cap-and-trade program. The commenter stated that any opt-in provision should be drafted to encourage participation and recognize cost-effective emission reductions tailored to the unique attributes of manufacturing facilities.

Response:

As already discussed in responses above, EPA maintains that certain cogeneration units should be included in the CAMR program and that opt-in will not be allowed.

5.6 STATE EMISSION BUDGETS

5.6.1 Coal Adjustment Factors

Comment:

Many commenters (OAR-2002-0056-1803, -2721, -2830, -2915, -3440, -3463, -3469, -3478, -3515, -3565, -4191, -4891) supported the proposed allocation ratios of 1, 1.25 and 3 for bituminous, sub-bituminous and lignite coals. One commenter (4891) stated that the proposed ratios should be adopted to apply to both the interim and Phase II caps. Several commenters (OAR-2002-0056-2915, -3440, -3463, -3478) noted that lignite units receive a 3:1 heat input based allocation of allowances with respect to bituminous units. This ratio is to account for the higher mercury content and lower energy content in lignite versus other coal types. The commenters stated that such an allocation is critical to the continued use of lignite given its higher mercury content with a higher elemental content that is harder to control, its lower heat content and the current lack of demonstrated mercury control technology for lignite coals. One commenter (OAR-2002-0056-3478) also stated that these baseline adjustment ratios were agreed upon by the industry in the Clear Skies Initiative negotiations.

One commenter (OAR-2002-0056-3478) added that not only does the higher mercury content, mercury speciation, lower heat content and lack of demonstrated mercury control technology for lignite support at least an adjustment factor of 3 (with sub-bituminous held at 1.25), but the variability in the existing data supports this as well. According to the commenter, in the preamble to this proposed rule, EPA stated: "Variability is inherent whenever measurements are made or whenever mechanical processes operate. Variability in emission test data may arise from one or more of the following areas: (1) The emission test method(s); (2) the analytical method(s); (3) the design of the unit and control device(s); (4) the operation of the unit and control device(s); (5) the amount of the constituent being tested in the fuel; and, (6) composition of the constituents in the fuel and/or stack gases." The commenter also stated that these baseline adjustment ratios were agreed upon by the industry in the Clear Skies Initiative negotiations.

The commenter believed that although the EPA made these comments in regards to setting the Maximum Achievable Control Technology (MACT) standard, it also would apply to setting an appropriate cap for mercury in a cap and trade system. The commenter has noticed in reviewing the 1999 Information Collection Request (ICR) data, considerable variability in all these parameters, especially with lignite. According to the commenter, ICR Part III test runs across the scrubber on Monticello Unit 3 indicated that mercury increased on one run and was reduced by 48 percent on another run. The commenter also stated that the tests on both Big Brown Unit 1 and Monticello Unit 1 both indicated that mercury was increasing across the

baghouse. The commenter stated that, therefore, there was a great deal of variability in the stack test method at their plants. The commenter has seen variability not only in the mercury content of the coal from mine to mine, but also seam to seam and even noticed seasonal variability. The commenter could not explain whether the seasonal variability was an actual phenomenon or some type of laboratory analysis difference. According to the commenter, the lignite mercury analysis performed for Part II of EPA's 1999 Information Collection Request showed the same seasonal trend for the samples from all four plants.

Several Texas State representatives and local officials (OAR-2002-0056-2119, -2204, -2221, -2228, -2232, -2356, -2428) endorsed the cap and trade approach and supported the allocations for lignite.

Several of the commenters (OAR-2002-0056-2830, -3469) requested that any adjustment to the proposed factors which might occur during the rulemaking process not reduce the allocations to lignite and thus disadvantage it in the market.

One commenter (OAR-2002-0056-2331) opposed EPA's proposal to use the maximum achievable control technology (MACT) emission rate criteria for different grades of coal as the basis for allocating Mercury allowances. The commenter recommended that the EPA adopt the CAA section 111 approach and maintain the compromise criteria of the December 15, 2003 proposal that were based on baseline heat input and adjustment factors for different grades of coal. The commenter believed this would not only be a more equitable interregional solution for allocating mercury allowances but would also not result in excessive fuel switching from coal to natural gas.

One commenter (OAR-2002-0056-2634) would support and prefer a well designed Cap and Trade program if the allocation methodology were modified to achieve a more fair and equitable allowance distribution and thus reduce the number of large winners and losers. In an effort to achieve a more equitable mercury allowance distribution, however, the commenter proposed three (3) allocation methodology options.

OPTION 1: The commenter Mercury Allocation Methodology using unit specific 1999 Elemental Mercury Emissions.

The commenter submitted that this methodology would achieve the major goals of:

- Being coal neutral. Does not utilize any coal category adjustment factors.

- Reducing the number of large winners and losers.

The commenter felt that the methodology proposed above utilizing the individual elemental mercury emissions would be the most equitable way of allocating mercury allowances. However, the commenter recognized that the methodology proposed in the NPR may not be substantially modified without seeking additional comments from interested stakeholders.

Therefore, the commenter proposed two alternate allocation methodologies that would apply to those units having high (90 percent plus) elemental mercury emissions.

OPTION 2: The commenter Mercury Allocation Methodology using adjusted HI factors for units that have 1999 elemental mercury emissions above 90 percent.

OPTION 3: The commenter Mercury Allocation Methodology using a set aside of 10 percent of the 2010 and 2018 allowances.

The commenter stated that at a minimum, the modified allocation under Options 1, 2, or 3, or under some other similar method, would need to be applied to units that presently have Spray Dryer Absorbers (SDA) for SO_2 control and Fabric Filters for particulate control and have mercury emissions that are above 90 percent elemental. The commenter believed that this adjustment for these units would be necessary and justifiable because the SO_2 control (SDA) is located upstream of the Fabric Filter. The commenter stated SDA tends to remove most of the gases that would potentially oxidize some of the mercury to a form to be removed in the Fabric Filter. The commenter stated further that units whose emissions are above 90 percent elemental have already achieved the maximum removal that these units are capable of achieving without the addition of advanced mercury control technology. This technology is envisioned as necessary for past 2018 compliance, but it is not intended for the 2010-2018 period when co-benefits are envisioned.

One commenter (OAR-2002-0056-2879) believed EPA's data are inadequate both quantitatively and qualitatively to produce supportable unit MACT emissions rates or, under a trading regime, supportable or equitable allowance allocations, and has detailed those deficiencies in Attachment A (See docket item OAR-2002-0056-2879).

If EPA proceeds with a cap and trade option, one commenter (OAR-2002-0056-2264) recognized and supported the need for adjustments in the allocations to recognize differences between bituminous and sub-bituminous coals. The commenter believed that EPA should develop better data and information on which to quantify the mercury adjustment factors.

One commenter (OAR-2002-0056-2944) believed the currently-proposed mercury emission limits, along with the similarly-weighted allowance distribution systems that were proposed, clearly look politically-derived to particularly favor some business interests at the expense of others. The commenter stated that the Environmental Protection Agency should adamantly reject regulatory schemes which so blatantly appear to sacrifice the nation's health to special interests.

One commenter (OAR-2002-0056-3522) stated that allowances should be allocated to sources in accordance with the emission factors developed as a result of WEST Associates' analysis and described more fully in the WEST Associates' comments. However, the commenter could accept the allowance allocation factors endorsed in the comments of the Edison Electric Institute.

One commenter (OAR-2002-0056-2835) submitted that while commenter members have varying viewpoints on the different possible methodologies, all of the commenter's members agreed that allowances should be allocated in a manner that reflects coal chemistry, mercury variability in the combustion fuel, and mercury removal efficiencies of available pollution control technologies.

One of the commenters (OAR-2002-0056-2725) stated that many questions remain regarding both the impacts of various coal types and the controls effective in mitigating each type's specific impacts. The commenter noted that the National Mining Association, recognizing that more data is needed to fully answer these questions, is recommending that the EPA hold off on assigning allocations among coal types until more complete information can be gathered and assessed. The commenter believed this suggestion has real merit and would be supportive of such a measured approach.

The commenter stated that should EPA determine that it must go forward with setting allocations on the front end through its proposed mercury trading program, the commenter urged the Agency to assure that those allocations are as equitable as possible. The commenter noted EPA has proposed a range of allocation options for mercury allowances, ranging from the allocation scheme proposed in the Clear Skies Act (i.e. allocate in the proportion of 1:1.25:3 for bituminous, sub- bituminous coal and lignite) to a scheme based on the mercury MACT proposal. In light of the problems with controlling mercury from sub-bituminous coal, the commenter believed that the Clear Skies approach provides too few allowances for Western sub-bituminous coal and suggested that EPA find compromise allowance allocation ratios that are more consistent with the science of mercury control.

One commenter (OAR-2002-0056-3463) stated that the EPA should allocate emission allowances for mercury to each affected unit directly in keeping with the Acid Rain Program. Similarly one commenter (OAR-2002-0056-2826) advocated that the cap-and-trade program's allowance allotment be based upon "heat input"–as with the Subpart H, NO_x credit program–and not on rank of coal.

One commenter (OAR-2002-0056-2160) stated that a cap and trade program should not include fuel adjustment factors.

One commenter (OAR-2002-0056-2452) submitted that within a section 112 or section 111 cap-and-trade context, they did not believe that it is appropriate for EPA to adjust allocations to the states or generating units based on coal-type adjustment factor (the commenter noted that EPA's currently proposed methodology applies adjustment factors to coal unit baseline heat input data with an adjustment of 1.0 for bituminous coal, 1.25 for sub-bituminous and 3.0 for lignite). The commenter believed that rather, a single allocation emission rate standard, applied to baseline generating unit heat input (without adjustment for coal-type) should be the basis for state and unit level allocations. The commenter asserted that under a cap-and-trade regime, there would be no need for EPA to address differences in coal-types as part of its allocation system. Units that were harder to control would have the option to go to the market to support their compliance needs. The commenter submitted that a single allocation

standard has worked well for the NO_x SIP Call (e.g. 0.15 lb NO_x/mmBtu) and companies have had the flexibility to choose the optimum mix of controls and allowance purchases for compliance at their generating units. The commenter believed a single allocation standard would also be more competitively neutral versus EPA's proposed allocation system that effectively "subsidizes" states and units with lower rank coals, particularly lignite. The commenter stated that it is quite possible that as mercury control technology evolves, that cost effective, high removal efficiency control technologies for lower rank coals will be developed. The commenter pointed out that in this case, EPA's proposal to provide lower rank coals with larger emission allocations would provide these units with a windfall relative to higher rank coals. Also, by lowering the compliance burden on lower rank coals, EPA would be potentially creating a self-fulfilling prophecy where highly effective control technology for lower rank coals would be under-developed versus what would be the case if all units received emission allocations based on the same standard.

One commenter (OAR-2002-0056-3431) stated that regulations for the control of mercury from utilities must not favor one coal type over another. The commenter believed the cap-and-trade proposal with adjustment factors for different coal ranks (i.e., types) affecting allocations and the MACT proposal with different emissions standards for different coal types, both inappropriately favor particular coal types. The commenter stated that these regulations should not unduly disadvantage generators based upon their coal type (i.e. bituminous, sub-bituminous and lignite). The commenter believed a regulatory approach that does not favor one coal type over another would be more efficient, cost-effective and equitable. According to the commenter, under the successful Acid Rain program, the allocation methodology did not favor one type of coal over another for sulfur content, but let the market set demand for a particular coal.

The commenter noted that EPA solicited comment on whether it should use the proposed MACT emission rates proposed in the Notice of Proposed Rulemaking as the basis for allocations. The commenter specifically opposed this approach since it would penalize plants that burn bituminous coal even more than the allocation approach proposed in the rule. The commenter also stated that the MACT proposal would disadvantage both producers and users of bituminous coal and would force the use of non-bituminous coal through blending. The commenter believed such blending would favor Western coals over Eastern coals and, at a minimum, increase transportation and coal costs for those who blend. The commenter added that blending of coals also would result in higher emissions rates as the proposal requires a monthly unit-specific weighted mercury emissions limit based on the proportion of energy output (in Btu) contributed by each coal type burned during the compliance period and each coal type's applicable emissions limit. According to the commenter, as sub-bituminous coal has a higher emission rate under the MACT proposal than bituminous coal, any blending of sub-bituminous coal with bituminous coal would result in a higher emission rate.

One commenter (OAR-2002-0056-3443) did not support the use of heat input adjustment multipliers and was against any further tinkering of the multipliers proposed by EPA. See 69 FR 12397 and 12406 (1.0:1.25:3.00). The commenter submitted that heat input adjustment factors would favor non-bituminous coals by allowing higher mercury emissions per TBTU. The

commenter believed this approach was not equitable nor environmentally sound since it would allow units to have higher emissions based entirely on fuel choice. The commenter noted that previous EPA cap and trade programs did not make such skewing adjustments favoring one coal rank over another. In fact, EPA's Acid Rain program was designed to prevent the market from bestowing preferential treatment on a particular coal rank. The commenter believed EPA's proposed factors were already generous to non-bituminous units in accounting for the higher emissions of non-elemental mercury from bituminous units. Pertinently, the intermediate and final cap of 24 and 15 tons per year respectively, would require reductions from bituminous units not only of most non-elemental mercury but also of the elemental kind. The commenter asserted that accordingly, further skewing of the ratios in favor of the non-bituminous units would essentially absolve these units of any control of elemental mercury.

One commenter (OAR-2002-0056-3437) questioned the allocation methodology. The commenter noted the baseline heat input would be the average of the 3 highest heat inputs during 1998-2002. The was consistent with the NO_x trading program. The commenter also noted however, EPA proposed to adjust the heat input based on the coal rank. This would not be consistent with the NO_x or Acid Rain programs. The commenter noted further that EPA claimed this would level the playing field based on the different mercury removal efficiencies with the control used to control PM, SO_2 and NO_x. It was not clear to the commenter how this would affect fuel switching, control options, or actual emissions. The commenter submitted that EPA must provide information on how allocations would be distributed using different methodologies so that more detailed comments can be filed. Absent any comparisons, the commenter believed emission rates should be used to determine allocations and budgets that would address any differences in coal types.

One commenter (OAR-2002-0056-3437) disagreed with the method for calculating state and unit budgets. The commenter believed the rule should not be structured to provide an advantage to one type fuel over another. The commenter suggested EPA should do like in the NO_x SIP Call; use an emission rate to determine allocations and budgets. This would avoid the need to adjust the heat input . The commenter stated the emission rates would address the differences in the ability to control mercury from different types of coal.

Many commenters (OAR-2002-0056-1854, -1969, -2067, -2160, -2180, -2375, -2519, -2535, -2560, -2597, -2634, -2661, -2718, -2725, -2835, -2850, -2861, -2862, -2867, -2879, -2895, -2897, -2900, -2903, -2918, -3406, -3521, -3537, -3546, -4132) requested changes in the mercury allocation adjustment factors. Many of these commenters (OAR-2002-0056-1969, -2375, -2519, -2560, -2597, -2661, -2718, -2725, -2850, -2862, -2867, -2897, -2903, -3198, -3521, -3546) supported a change in EPA's proposed mercury allocation adjustment factors to 1.0 for bituminous units, 1.5 for sub-bituminous units and 3.0 for lignite units. One of these commenters (OAR-2002-0056-3546) submitted that allowances should be allocated in a manner that reflects coal chemistry and mercury variability between coals. The commenter noted that chlorine in coal plays a major role in the type of mercury that is emitted. Higher chlorine levels result in a greater percentage of oxidized mercury and lower amounts of chlorine in coal result in more elemental mercury. The commenter stated that sub-bituminous and western bituminous coals tend to be very low in both mercury and chlorine content compared with the concentrations

found in eastern bituminous coals. Data from the 1999 Information Collection Rule showed that western plants emit lower concentrations of total mercury than eastern plants and that elemental mercury is the form of mercury primarily emitted. The commenter noted that elemental mercury is the form of mercury that is the most difficult to control. Ionic mercury can be readily captured in existing particulate controls and flue gas desulfurization systems. The commenter stated that EPA's proposed mercury MACT floor limit for sub-bituminous coal recognizes the technical challenge of controlling elemental mercury. However, according to the commenter, the proposed allocation adjustment factors for the various coal ranks did not adequately reflect the differences in coal chemistry and mercury variability between sub-bituminous and eastern bituminous coals. The commenter believed that the proposed 1.25 allocation adjustment factor for sub-bituminous and western bituminous coals needed to be increased to at least 1.5.

The commenter (OAR-2002-0056-3546) stated that the proposed allocation adjustment factors also do not differentiate between western bituminous coal and eastern bituminous coal; both coal types receive the same adjustment factor. The commenter claimed that this would treat EGU's that burn western bituminous coal unfairly because the physical, chemical and emission characteristics of western bituminous coals are substantially more similar to western bituminous coal than eastern bituminous coal. The commenter submitted there are often times subtle differences between the physical properties of western bituminous and sub-bituminous coals. While these physical tests determine whether a coal is bituminous or sub-bituminous, it does not reflect that both ranks of western coal have low mercury and chlorine concentrations, and thus similar mercury emission characteristics. The commenter supported an adjustment to the coal rank multiplies that would combine western bituminous coal with sub-bituminous coal.

Another of the commenters (OAR-2002-0056-2850) noted EPA is suggesting a 1.0, 1.25 and 3.0 relative allocation of mercury allowances to bituminous, sub-bituminous and lignite coals respectively, based on heat input. The commenter stated that, in effect, sub-bituminous coal units incur a relatively more aggressive control requirement than would be applied under the EPA proposed MACT levels and it would be expected that utilities burning sub-bituminous coals would find it most economic to buy credits from bituminous coal units that face lower mercury compliance costs. According to the commenter, a ratio for allocation of 1, 1.5 and 3 would be more equitable and should be considered by EPA as an alternative.

One of the commenters (OAR-2002-0056-3537) stated that although there are no commercially available control technologies specifically designed today for reducing mercury emissions and monitoring data from Utility Units of mercury emissions is sparse, there is some available data. The commenter noted that such data indicates that the three types of mercury emitted in flue gas–particulate, ionic and elemental–vary according to the three most common ranks of coal–bituminous, sub-bituminous and lignite being combusted in the Utility Unit. The commenter also noted that generally speaking, the lower the coal rank, from bituminous to sub-bituminous to lignite coals, the more difficult it is to control mercury. The commenter stated that differences in elemental constituents in coal is just one variable affecting the ability to control mercury emissions, since mercury speciation dictates the level of control that can be achieved using existing air pollution control equipment. The relationship between coal chemistry and mercury speciation is not totally understood. The commenter pointed out it is

known, however, that chloride content, sulfur content and ash characteristics can all affect mercury speciation. In conclusion, the commenter stated that conventional pollution control technologies will be least effective on units combusting lignite and most effective on those that burn bituminous coals, with sub-bituminous units falling somewhere between the other two coal ranks.

The commenter (OAR-2002-0056-3537) stated therefore, any cap and trade program which uses heat input as the basis for allocation must, to be equitable, contain adjustment factors to account for the varying coal ranks that will be combusted across the industry, and the associated differences between coal ranks related to the difficulty in controlling mercury emissions. The commenter noted that EPA proposed heat input adjustment factors of 1.0 for bituminous units, 1.25 for sub-bituminous units and 3.0 for lignite Utility Units. The commenter believed that the heat input factor for sub-bituminous coal is too low relative to the other coal ranks and should be increased to 1.50, which, based on the available data, would better represent the relative difficulties of controlling mercury emissions from the three coal ranks.

One of the commenters (OAR-2002-0056-2375) stated that the method of allocating mercury trading credits among affected sources can be established in a manner that would provide protections against potential fuel-switching or creating an unequal playing field between subcategories of coal users. Studies by WEST Associates (WEST) and the commenter showed that the multiplier for sub-bituminous units should be at least 1.5 to account for the difficulty of controlling mercury emissions from western coal. The commenter submitted that the vast majority of coal-fired generators in the U.S. have agreed to compromise multipliers of 1.0, 1.5, and 3.0 for bituminous, sub-bituminous, and lignite, respectively. The commenter supported these multipliers both as representing a reasonable compromise and as having a sound technical basis, although a higher multiplier for sub-bituminous could be justified based on the available data.

One of the commenters (OAR-2002-0056-2519) noted that WEST Associates, of which the commenter is a member, was submitting detailed comments on several issues associated with the C & T program, and the commenter endorsed those comments by reference. Specifically, those issues relate to the multipliers used for different coal types in calculating the allowance allocations.

Another of the commenters (OAR-2002-0056-1969) expressed concern that EPA's proposed coal heat input adjustment factors of 1.0 for bituminous coal, 1.25 for sub-bituminous coal, and 3.0 for lignite are not equitable for the purpose of allocating future mercury allowances. According to the commenter, EPA has not adequately considered the fuel-specific impacts of the co-benefit level mercury emissions reductions. The commenter believed that as a result, allowances would not be equitably allocated among the coal ranks. The commenter stated that specifically, the optimum level of co-benefits would occur when all particulate and oxidized mercury have been removed from the flue gas with only elemental mercury remaining. According to the commenter, Table 1 (see docket) estimated the elemental portion of each coal rank based on the 1999 ICR data. Table 2 (see docket) projected the annual emissions in tons per year on the basis of EPA's proposed 1:1.25:3 coal heat input adjustment factors. The

commenter noted that the relative margin between the ICR -based 1999 mercury emission and the EPA proposal was considerably smaller for sub-bituminous coal as compared to the other fuels. The commenter asserted that more equitable heat input adjustment factors would be 1.0 for bituminous, 1.5 for sub-bituminous and 3.0 for lignite (See Table 3 in docket).

One of the commenters (OAR-2002-0056-2661) stated there is an understood industry-wide and regulatory concern that sub-bituminous coal users are at a disadvantage to meet mercury reduction requirements because of the unique coal chemistry involved in burning this fuel type. The commenter submitted this inherent difference should be reflected in the heat input adjustment factor or multiplier for subbituminous coal ranks. As proposed, the commenter supported a 1.5 or higher adjustment factor for users of the differing coal types, specifically for sub-bituminous coals. The commenter agreed with EPA's assertion that the same percentage of non-elemental mercury first be reduced at a proportional rate across the board between the variety of coal ranks.

Another of the commenters (OAR-2002-0056-2718) supported The Allocation Of Mercury Allowances Based On Reasonable Multipliers. The commenter agreed with industry consensus, with some refinements given the commenter's unique situation, that for Phases I and II, the multipliers that most appropriately reflect the mercury reductions that would be achieved as co-benefits of CAIR NO_x and SO_2 reductions are 1.0, 1.5 and 3.0 for bituminous, sub-bituminous and lignite, respectively. For Phase III, no multipliers–or, put differently, multipliers of 1.0, 1.0, and 1.0–would be appropriate. Given that mercury reductions are a nationwide, rather than regional, concern, the commenter believed that EPA's final rule should equitably distribute the burden of mercury reductions among regulated utilities and coal producers nationwide.

Another of the commenters (OAR-2002-0056-2560) stated that at an absolute minimum the commenter supported a 1.5 or higher heat input adjustment factor for boilers burning sub-bituminous coals as compared to bituminous coals. The commenter added that where sub-bituminous and bituminous coals are blended for firing, the heat input adjustment factor should reflect the percent of blend.

Another of the commenters (OAR-2002-0056-2903) stated that mercury trading credits should be allocated among affected sources in a manner that recognizes the differences in control opportunities and costs among coal types and preserves fuel diversity, yet avoids unintended fuel switching and, when all factors are considered, still preserves a balance among subcategories of coal users. The commenter believed that the appropriate multipliers, taking such considerations into account, should be 1.0 for bituminous, 1.5 for sub-bituminous and 3.0 for lignite. The commenter noted that the majority of coal-fired generators in the U.S. have now agreed to support such multipliers.

One of the commenters (OAR-2002-0056-2597) noted that a major issue embedded in the model cap-and-trade program concerns how mercury allowances would be allocated among the different subcategories of coal types. The commenter stated that in order for the model program to work most efficiently and cost-effectively, it is critical that no coal type is unduly

disadvantaged based on the allowance allocation scheme adopted by EPA. The commenter believed the most equitable allocation method uses adjustment factors of 1.0 for bituminous, 1.5 for sub-bituminous and 3.0 for lignite.

One commenter (OAR-2002-0056-2895) stated that while the proposed allowance allocation factors do reflect the difficulty in controlling for mercury amongst the different coal ranks, the commenter believed that the proposed factors of 1.0 for bituminous coal, 1.25 for sub-bituminous coal, and 3.0 for lignite need to be revised. The commenter believed that the multipliers developed by WEST Associates based on its technical analysis of coal chemistry and mercury variability between coals are more reflective of the difficulty in controlling for mercury amongst the different coal ranks. These multipliers are 1.0 for bituminous coal, 1.8 for sub-bituminous coal, and 3.6 for lignite. The commenter was also aware that a large number of companies in the industry were supporting adjustment factors of 1.0 for bituminous coal, 1.5 for sub-bituminous coal, and 3.0 for lignite. If the WEST Associate numbers are not selected as the multipliers in the final rule, the commenter recommended the use of the aforementioned multipliers (1.0, 1.5, 3.0) supported by much of the industry.

One commenter (OAR-2002-0056-2835) supported minor adjustments to allocation methodology for mercury allowances based on type of fuel burned. The commenter agreed with EPA's decision to allocate mercury allowances based on the ability to control mercury from the three major types of coal: bituminous, sub bituminous, and lignite. Furthermore, the commenter believed that the adjustment factors selected for the mercury allocations should represent an equitable sharing of the burden among coal types to achieve the required mercury reductions. The specific mercury allocation position outlined below reflected a compromise position among the commenter members, which collectively have burned a diverse mix of coal types including eastern and western bituminous and sub-bituminous coals and lignite.

The commenter stated that initial mercury reductions would be achieved through the imposition of the SO_2 and NO_x controls required by the CAIR. These reductions are referred to as mercury co-benefit reductions. The commenter also stated however, additional reductions would be required beyond projected mercury co-benefit levels, particularly during the later years of the mercury control program. The commenter submitted this additional mercury reduction burden for each coal type could be measured in several ways. These included percent reduction (pounds reduced divided by current pounds emitted for each coal type), equal reduction on a Btu basis (pounds reduced divided by total coal type Btu), or cost of required reductions on a Btu basis (dollar cost of reductions divided by total coal type Btu).

The commenter believed costs on a Btu-basis may be the best measure of the "fairness" of a given set of allocation factors. The commenter has examined the range of removal costs for the various coal types. The commenter's analysis indicated that existing pollution control technologies can, on average, achieve the following $/pound removal rates: $20,000/ pound for lignite, $25-$30,000/pound for bituminous, and $30-$40,000/pound for sub-bituminous. Another relevant factor examined by the commenter was the incremental mercury reductions estimated to be necessary after mercury co-benefit reductions have been achieved through implementation of the CAIR controls. Finally, the commenter considered variations in the form

of mercury and level within each coal type as well as the National Energy Technology Lab's data on coal use by type.

The commenter noted that the considerations noted above indicated that the proposed allocation factors of 1.0 (bituminous), 1.25 (sub-bituminous), and 3.0 (lignite), although directionally sound, fall far short of equitably allocating the mercury control obligation among coal types. Among other things, EPA's proposed factors failed to reflect adequately the difficulty in removing elemental mercury from those units burning sub-bituminous coal and over-allocate mercury allowances to those units burning lignite. The commenter submitted furthermore, these considerations noted above weighed in favor of EPA making the following changes in the proposed mercury adjustment factors. The commenter believed that adjustment factors should represent an equitable sharing of the burden among coal types for necessary mercury reductions when the cost of required reductions on a Btu-basis is evaluated for each coal type. The commenter stated that these factors would not achieve equality among the coal types with respect to cost per Btu, but would be much more equitable than the proposed factors. The commenter believed that these allocation factors should be used for each phase of a cap-and-trade program:

Coal Type	Proposed Adjustment Factor	Revised Adjustment Factor
Bituminous	1	1
Sub-Bituminous	1.25	1.5
Lignite	3	2.5

Several commenters (OAR-2002-0056-2898, -2907) supported allowance adjustment factors as proposed by WEST Associates in Table 2 of WEST's multivariable analysis. The commenters stated these allocation factors are: Bituminous 1.0; Sub-bituminous 1.8; and Lignite 3.6. One of the commenters (OAR-2002-0056-2907) stated they supported these allocation factors in light of the difficulty associated with controlling sub-bituminous coal. The commenter believed these allocation factors would be more consistent with the science of mercury and control technology.

One commentor (OAR-2002-0056-2180) noted that the proposed allowance adjustment factors for determining allowance allocations to units are 1.0 for bituminous coal, 1.25 for sub-bituminous coal, and 3.0 for lignite, and that these factors appeared to originate from the proposed Clear Skies legislation. The commenter stated that, however, the adjustment factors in the proposed legislation have not been scrutinized for scientific accuracy. The commenter noted that the proposed rule's preamble states that the proposed adjustment factors "are considered to be directionally correct based on test data currently available" and the factors "are intended to equitably distribute allowances to the affected industry." The commenter stated that, however, there is no information in either the rule's preamble or in the mercury rulemaking docket that scientifically justifies the proposed adjustment factors. The commenter noted that the preamble indicates that EPA may apportion allowances based on proposed MACT emission limits. According to the commenter, the proposed MACT emission limits suggested that the

sub-bituminous allowance adjustment factor is set too low. The commenter stated that the ratio of the sub-bituminous proposed MACT limit to the bituminous proposed MACT limit was 2.9, while the ratio of the sub-bituminous to the bituminous proposed adjustment factors was only 1.25. According to the commenter, the apportionment process based on MACT limits could be a step in the right direction, as MACT limits in the proposal are based on coal subcategories reflecting coal rank, and the proposed MACT limits are based on EPA's analysis of data. The commenter stated that, however, without knowing what the final MACT limits would be, how the limits were scientifically justified, and how the limits would be translated into the equivalent adjustment factors for allocating allowances, it would not be possible to specifically support the proposed alternate apportionment approach at this time. The commenter's coal capacity consisted of about two-thirds sub-bituminous and one-third bituminous coal. Therefore, the commenter had a direct interest in having appropriate and scientifically justified adjustment factors reflecting the various coal ranks. The commenter asserted that the final mercury trading rule should include a complete scientific analysis and explanation of the final adjustment factors that are adopted. The commenter offered that one alternative to consider would be to set adjustment factors based on the ratio of remaining emission levels for each coal type after application of co-benefit controls. According to the commenter, remaining emission levels for this purpose would consist of elemental mercury emissions (assuming minimal emission reduction with co-benefit controls) plus non-elemental mercury emissions (representing the percentage of non-elemental mercury not captured by co-benefit controls).

One commenter (OAR-2002-0056-4132) cautioned that EPA should be careful not to manipulate mercury allowances to simulate a technology-based standard. The commenter noted that EPA has garnered significant praise over the economic successes of cap and trade programs implemented relative to SO_2 and NO_x. Critical to the success of these programs was the fact that there were strong economic incentives for all affected emitters to develop a low-cost solution to reducing their emissions.

The commenter noted that in these proposals EPA is considering an unusual allocation of mercury allowances at paragraph 60.4142. Sub-bituminous coal users may receive 25 percent more mercury allowances per mmBtu than bituminous coal users. Lignite coal users may receive 200 percent more mercury allowances per mmBtu than bituminous users. (The mechanism for this unusual allocation are coal-specific annual heat input multipliers 1.0, 1.25, and 3.0). The commenter believed this artificial manipulation of a cap and trade program had the potential to create several adverse outcomes:

- It appeared to provide special subsidies to the coals that emit the highest amount of mercury per mmBtu.

- It allocated large lignite and sub-bituminous coal users mercury allowances equal to or exceeding their current mercury emissions. As a result they would have little incentive to make capital improvements to reduce mercury emissions. Theoretically, they may backslide and emit more mercury in the future than in the base year.

- Bituminous coal users were essentially shorted in their allocations of mercury allowances. This would cause higher levels of mercury control with higher incremental control costs than would possibly be experienced in the traditional, unmanipulated allocation program.

- The allocation of mercury allowances to the sub-bituminous and lignite coal users would have the potential to incentives use of these types of coal. This would not be a desirable outcome, since mercury emissions from these coal types do not respond well to existing air pollution controls.

The commenter stated that the remedy for the above outcomes would be to do away with the use of any "annual heat input multipliers." The commenter suggested that alternatively the annual heat input multipliers should be reduced in magnitude and at the very least, they should not be made larger.

One commenter (OAR-2002-0056-2897) stated that any cap-and-trade approach must include allocation factors that address the need for subcategorization. The commenter believed the factors proposed by the EPA (1.0 for bituminous, 1.25 for subbituminous and 3.0 for lignite) did not adequately address this issue. The commenter stated that these factors were based on EPA's analysis of the ICR data, which has been shown to be inappropriate for any regulatory purpose. According to the commenter, even the EPA states that these factors are only "directionally correct", this was a completely inadequate basis for setting a regulatory standard. The commenter urged the EPA to thoroughly reassess the proposed allocation factors.

The commenter pointed out as the first phase reduction targets were based on EPA's estimates of actual reductions achieved through co-benefits and as it was widely acknowledged that sub-bituminous coals obtain lower co-benefit reductions than bituminous coals it would be essential that the EPA adopt appropriate allocation factors. The commenter stated that without appropriate allocation factors sub-bituminous users who could not achieve significant co-benefit reductions would be forced to buy allowances from bituminous users who can. According to the commenter, this would obviously result in wealth transfer from users of sub-bituminous to users of bituminous coals and promote fuel switching. The commenter asserted that claims that the incorporation of any allocation factors will result in wealth transfer from bituminous users to sub-bituminous users were clearly false and ignored the reality of lower co-benefit reductions for sub-bituminous coals.

The commenter noted that other industry commentators are proposing factors of 1.0 for bituminous, 1.5 for sub-bituminous and 3.0 for lignite based upon the relative proportions of elemental mercury produced by the three different coal ranks. The commenter believed given the limitations in the ICR database, basing the factors on the relative proportions of elemental mercury would likely be a more robust approach. According to the commenter, because the amount of elemental mercury produced effectively reflects the difficulty of control, these factors are, in the long term, more likely to result in an even distribution of the compliance burden between coal ranks. The commenter stated that, however, because plant configuration also affects mercury capture and as sub-bituminous coal is typically burned in plant configurations

that produce little co-benefit capture, e.g. plants with dry scrubbers, a sub-bituminous factor based purely on elemental mercury content will be inadequate to avoid fuel switching. The commenter asserted that in order to account for differences in plant configuration allocation factors of 1.0 for bituminous, 1.9 for sub-bituminous and 2.95 for lignite, as proposed by the industry majority during the CAAAC process, appear to be the most appropriate. The commenter stated that these factors have been calculated from the floors developed by industry majority consensus position, which included representatives from the unions, all major coal producing regions and a large proportion of the electric utility industry.

One commenter (OAR-2002-0056-2634) noted that the adjustment factors are supposed to account for the difference in coal chemistry among the different types of coal ranks. The commenter pointed out that some of the major differences among coals is the amount of elemental mercury and the chlorine content.

According to the commenter, bituminous coals are generally high in chlorine content which tends to oxidize the elemental mercury and thus facilitate its removal with add on SO_2/NO_x/PM emission control equipment. Sub-bituminous coals, however, have little or no chlorine content and thus mercury oxidation is correspondingly less. The commenter stated it is much more difficult to remove the elemental portion of the mercury in flue gas for sub-bituminous coals regardless of control technology, including the addition of activated carbon which is the most promising technology but is yet unproven. The commenter submitted that because sub-bituminous coals typically have a much higher percentage of elemental mercury, the adjustment factors should proportionally provide sub-bituminous coal users with a higher allocation.

The commenter stated that given this fact, it follows that the adjustment factor for sub-bituminous coal should be considerably higher than what is proposed in the NPR. The commenter believed the ratio that would result from the proposed MACT floor contained in the section 112 MACT portion of the NPR appeared to be the most reasonable. These factors would be 1.0 for bituminous, 2.9 for subbituminous, and 4.6 for lignite. The commenter noted ICR III speciation data showed that the average ratio of elemental mercury between sub-bituminous and bituminous coals is 2.3. The commenter stated that this analysis supported the 2.9 adjustment factor for sub-bituminous coals because it demonstrated and considered the inherent difficulties of controlling elemental mercury; however, a multiplier of 2.3 for sub-bituminous could be justifiable and defensible.

One commenter (OAR-2002-0056-3406) noted that EPA proposed to allocate allowances to bituminous coal-burning units on the basis of 1.0 times their overall heat input, and to sub-bituminous units on the basis of 1.25 times their heat input. The commenter recommended against distinguishing between bituminous and sub-bituminous units for these purposes. In view of the efforts underway to develop mercury control technologies for sub-bituminous coal, and the role of stringent standards in driving technology development, the commenter believed that bituminous and sub-bituminous units should be treated the same for allocation purposes. Similarly, the commenter believed that constraint should be exercised in applying adjustment factors to lignite.

One commenter (OAR-2002-0056-1854) believed that a properly implemented cap and trade program could reduce the overall cost of mercury control for coal-fired electric generating units. The commenter supported the cap and trade baseline heat input adjustment factors that are listed in this proposed rule on page 12445, i.e., 1 for bituminous, 1.25 for sub-bituminous and 3 for lignite coals. The commenter noted that these factors resulted from a carefully crafted agreement reached in the Clear Skies Initiative. However, the commenter stated that with their increasing knowledge of the mercury content of lignite and the inability to control it with proven technology, they did have concerns that a factor of 3 for lignite may still be very restrictive.

One commenter (OAR-2002-0056-2067) stated that it is dependent on Wyoming Powder River Basin (PRB) subbituminous coal to fuel its primary generating resource. According to the commenter, PRB coal accounts for nearly 40 percent of the coal used for generating electricity in the United States. The commenter supported the use of multipliers for the coal ranks based on sound scientific data and noted that the EPA ICR data is a starting point but should not be the exclusive source of such data. According to the commenter data collected by the Subbituminous Energy Coalition (SEC), through the Western Research Institute in Laramie, Wyoming, provided a more recent set of test data that should be considered. The commenter recommended that at a minimum, the appropriate multiplier for sub-bituminous coal should be 1.5.

One commenter (OAR-2002-0056-2861) noted that EPA has proposed to apply an adjustment factor to the baseline heat input used to allocate allowances depending on the coal rank consumed during the baseline period. The commenter stated that the proposed factors of 1.25 for sub-bituminous and 3.0 for lignite would provide additional allowances to those coal ranks, leaving fewer allowances for bituminous coal users. The commenter submited that EPA has proposed those factors for distributing the allocations for 2018 and presumably for 2010 as well. The stated basis for the factors was that boilers that burn sub-bituminous or lignite coals presumably emit more mercury in the elemental form which is more difficult to capture with SO_2 and NO_x technologies. The commenter believed that the use of adjustment factors provides a significant advantage to sub-bituminous and lignite coals. The commenter asked that EPA re-evaluate the technical basis for adjustment factors and at a minimum to reject any request to make those factors higher than what the Agency has proposed.

The commenter did not support the 1.5 adjustment factor for sub-bituminous coal being proposed by UARG and the Edison Electric Institute (EEI). The commenter claimed that neither UARG nor EEI have provided a sufficient technical justification for the higher factor. The commenter noted that those arguing for the higher allocation adjustment factor are assuming that sub-bituminous coals will achieve no control of elemental mercury. The commenter believed that while that assumption may be somewhat appropriate if considering the level of reduction associated with the co-benefits of SO_2 and NO_x control, the analysis is entirely inappropriate when considering allocations of mercury at either a 24 ton or a 15 ton cap level.

The commenter submitted that in order for the industry to meet either a 24 ton or 15 ton emissions cap, it would be necessary for utilities across the nation to take broad actions to install technologies that are under development to control both elemental and non-elemental mercury, with an overall 80 percent reduction requirement from the total mercury in coal. The commenter

stated that the advanced technologies that are under development are intended to be applicable to a wide range of coals, including bituminous, sub-bituminous, and lignite. The commenter believed factors other than coal rank may be more important to the ability to reduce mercury emissions. For example, a facility that is equipped with a baghouse may be able to achieve substantial elemental mercury reduction through use of carbon injection.

The commenter claimed that even using heat input alone to distribute either a 24 ton or 15 ton cap would provide a significant advantage to sub-bituminous coal users. The commenter noted that sub-bituminous coal has the lowest average mercury content of the coal ranks, as documented by EPA data from the mercury ICR. The commenter stated that using an adjustment factor of 1.0 (using unadjusted heat inputs to allocate allowances) would actually provide nearly a 50 percent bonus to sub-bituminous coals compared to the allocations if all coal ranks were expected to achieve the same percent reduction. The commenter claimed that EPA's proposed adjustment factor of 1.25 for sub-bituminous coal amounts to an allocation windfall bonus of nearly 90 percent. The commenter also claimed that for lignite coal, the proposed adjustment factor of 3.0 would be equivalent to an allocation windfall bonus of nearly 150 percent.

The commenter asserted that additional allocations for sub-bituminous and lignite coal would mean that bituminous coal users would be required to make proportionally greater reductions, or purchase more allowances than would otherwise be required. The commenter submitted that EPA has not provided a technical basis to justify this subsidization of sub-bituminous and lignite users by bituminous users, but has simply declared that the factors are "directionally correct." The commenter submited moreover, EPA has not indicated why it is necessary to give this advantage to sub-bituminous and lignite coal producers and to punish bituminous coal producers. The commenter stated EPA must provide a compelling justification for such economic policy choices and impacts. The commenter believed the fact that the Clear Skies legislation included adjustment factors for sub-bituminous and lignite coal was not a justification for EPA to include them in a mercury rule. The commenter submitted that unlike Congress, EPA must provide adequate technical justification for its rule, which in the case of its proposed adjustment factors it has failed to provide. Without a reasonable technical basis, the commenter believed the adjustment factors were arbitrary and should not be used for establishing a regulatory control program. The commenter submitted that providing these bonus allocations would be an energy and economic policy decision that would provide an advantage for states that have historically produced and/or used certain coal supplies. The commenter also submitted it is not a decision based on future environmental control requirements and effectiveness. The commenter predicted the consequences for states that have used bituminous coal exclusively, and those states engaged in the mining of bituminous coals, are millions of dollars for additional controls or allowance purchases, limited ability for development of new coal facilities due to a shortage of allowances for bituminous users, and lost jobs and income for industry and coal miners.

While the commenter believed that the use of adjustment factors would not be warranted, if EPA finalizes a cap and trade program beginning in 2010 which includes adjustment factors for sub bituminous and lignite coals, the commenter recommended that both adjustment factors be gradually eliminated on a sliding scale through 2018 to reflect the fact that advanced

technologies and the stringent cap will require control of all species of mercury. Under the alternate proposal that the commenter and UARG are recommending (co-benefits with no cap in 2010, followed by a two-phase cap and trade program beginning in 2015), the commenter recommended no adjustment factors be included. In any case, the commenter was not aware of any credible analysis that would support the adjustment factors higher than those that EPA has proposed as some groups are advocating, and EPA should reject those suggestions.

One commenter (OAR-2002-0056-2879) stated that allowance allocations under a trading program must be done equitably. The commenter believed that an allowance allocation using the proposed MACT emissions rates would simply convert the form of the advantage conferred on sub-bituminous coal from coal switching to a transfer of allowances, with hundreds of millions of dollars flowing each year from bituminous coal users to sub-bituminous coal users in the form of excess allowances. The EPA should propose a supportable and equitable allowance allocation scheme that does not overtly favor one coal rank over another. (Note See detailed explanation in docket item.)

One commenter (OAR-2002-0056-2535) believed that if EPA's proposed mercury adjustment factors (1.0; 1.25; 3.0) were used in conjunction with EPA's assumed 34-ton co-benefit level in 2010, a corresponding mercury emission limit could be calculated. Using the assumptions described, the corresponding mercury emission limit would be in the ballpark of 2.6 lb Hg/TBtu (bituminous coal), 3.2 lb Hg/TBtu (sub-bituminous coal), and 7.8 lb Hg/TBtu (lignite coal). This calculation showed that EPA's proposed mercury adjustment factors represent a dramatically different regulatory scheme than that proposed under the MACT program (2 lb Hg/TBtu (bituminous coal), 5.8 lb Hg/TBtu (sub-bituminous coal), and 9.2 lb Hg/TBtu (lignite coal)), as there was relatively little "subcategorization" in the proposed adjustment factors between bituminous and sub-bituminous coal. The commenter pointed out there are dramatic differences between Wyoming sub-bituminous coal and other sub-bituminous coals. These differences include higher mercury content than the EPA's "average" sub-bituminous coal mercury content of 5.74 lb Hg/TBtu, and lower capture rates than some other sub-bituminous coals largely based on the high elemental to total mercury ratio in the coal (evidenced by the lack of Wyoming PRB plants among the top performing units). EPA stated in the allocation memorandum cited above that "These adjustment factors are considered to be directionally correct based on the test data currently available." The commenter asserted the allocation process is critically important to the coal industry, regardless of coal rank. "Directionally correct" would not be a sufficient basis on which to set adjustment factors that are so crucial to understanding market implications. For this reason, the commenter would support EPA taking the necessary time to determine the accuracy and validity of the data prior to setting the adjustment factors. This approach would allow EPA to better understand the current state of control technology, and how different coal ranks behave with that technology. If EPA opts not to go this direction, then the commenter would be forced to support the mercury adjustment factors based upon EPA's proposed MACT emission floor numbers–those being 1.0 for bituminous; 2.9 for sub-bituminous; and 4.6 for lignite.

One commenter (OAR-2002-0056-3198) stated that any allocation factors must address the need for sub-categorization, and the factors currently proposed by the EPA (1.0, 1.25 and

3.0) did not adequately address this issue. The commenter stated that these factors were based on EPA's analysis of the ICR data and would be inappropriate for any regulatory purpose. The commenter pointed out that EPA stated that their analysis is only "directionally correct," which is an insufficient basis for setting a standard of this significant importance. The commenter urged the EPA to thoroughly reassess the proposed allocation factors. The commenter asserted that there is no rush to judgment in setting these factors, and EPA can take the appropriate time to obtain and analyze the proper factors. Absent this process and EPA moves forward to set the factors at this time, the commenter believed that factors should be set somewhere in the range of the proposed EPA MACT emission limits for mercury.

One commenter (OAR-2002-0056-2918) asserted the rulemaking must take into consideration both coal chemistry (primarily the chlorine content) and mercury variability between coals both as a total concentration and elemental fraction. The commenter submitted that doing so would result in a regulatory approach that addresses both the environmental impacts of near-field deposition of oxidized mercury and the long-range atmospheric transport of elemental mercury.

The commenter noted that the NPR recognized distinctions in coal chemistry by proposing to use allocation adjustment factors for each coal rank. These allocation factors are intended to compensate for differences in the efficacy of mercury control based on coal type.

The commenter stated that they undertook extensive technical work to determine the most appropriate manner to address mercury variability in developing a mercury MACT floor. The commenter suggested using this work as the basis to develop mercury allocation factors under a cap and trade program that would reflect actual mercury variability. The commenter believed that the relative difference between the proposed mercury MACT floor levels for each coal rank would be a good surrogate for weighting the allocations of future mercury emission credits between units burning these coal types, i.e., the cap and trade multipliers should reflect coal chemistry to the same extent as the proposed MACT limits.

The commenter noted that the proposed MACT floors contained in the section 112 MACT portion of the NPR would produce the following allocation factors for various coal ranks: bituminous–1.0; sub-bituminous and western bituminous–2.9; and lignite–4.6. While the commenter supported these allocation adjustment factors, the commenter was concerned that there may be inadequate basis for these derived factors. Alternatively, the commenter suggested, based on its technical analysis, using the following allowance multipliers: bituminous–1.0; sub-bituminous and western bituminous–1.8; and lignite–3.6.

One commenter (OAR-2002-0056-2918) wanted to bring to EPA's attention that there are member facilities (the commenter is a coalition of utilities) that, because of the high percentage of elemental mercury emitted by their coal (90-99 percent), would not receive adequate allowance allocations under any set of multipliers. According to the commenter, some of these facilities already have SO_2/NO_x/PM controls, but they would receive considerably fewer allowances than needed to operate based on ICR data for their 1999 emissions. This would be true even in 2010 with a cap set at the level of co-benefits achieved through installation of

control technology at sources covered under the CAIR. The commenter claimed that these member sources would therefore be forced to purchase allowances in Phase I. For the facilities that would have to purchase allowances, the commenter recommended that an additional allocation adjustment factor be applied that promotes equitable allowance distribution, particularly in Phase I of the cap and trade program.

One commenter (OAR-2002-0056-2900) believed that EPA's proposed adjustment factors are directionally correct but requested that the Agency re-evaluate the appropriate levels for the adjustment factors in light of the data submitted by other groups that have analyzed this issue.

One commenter (OAR-2002-0056-3437) noted that in the SNPR, EPA continued the methodology for basing allocations on the unit's proportionate share of the baseline heat input to total heat input. The commenter pointed out that this way would not use an emissions rate, but would simply divide the toal cap among individual units based on heat input. The commenter questioned how this would affect actual reductions? The commenter also questioned whether this could lead to some units being uncontrolled and allowing allowances to be transferred to other units so that even more units would be uncontrolled? The commenter stated that EPA proposed an alternative method that would use the proposed MACT limit and the proportionate share of heat input to establish unit allowances. In both cases the state budget would be the sum of the unit's allowances. The commenter supported using an emission rate that would reflect cost effective control and would more effectively limit individual units and result in more units having to control emissions. The commenter believed the allocation budgets should be based on an emisson rate that reflected adequate and reasonable reductions of mercury similar to that in the NO_x SIP call. The commenter submitted that EPA needs to provide comparisons of the final allocations based on the proposed methods.

One commenter (OAR-2002-0056-2181) believed the Rule's proposed allocation method for determining individual State budgets was flawed because it would adopt two market-distorting foundations. First, it would base the allocation on historic heat input; thus rewarding those States with the most inefficient fleet of electric generating capacity. Second, by subcategorizing the allocation formula based upon fuel sources and granting more allowances to higher cost-of control coal types, the proposed rule also would reward some sources at the expense of other sources. The commenter claimed that these proposed subcategorizations were based on expectations of mercury control costs that are not well documented and would defeat the cost-minimization function of the trading program. Neither of these two foundations would establish the fundamental signals that will lead to a dynamic trading program that would allow markets to work in the most cost effective manner. The commenter pointed out that the negative response from States to this skewing of the allocation system highlighted the problem of trying to prejudge the compliance response. The commenter submitted that the most equitable and effective choice would be to treat all sources equally in the allocation program and allow the market to determine the least-cost approach to reducing emissions. As an alternative, the commenter recommended that EPA should structure the State budgets on an output basis (lb/MWhr) without regard to subcategories of fuel. This method would be the best approach for establishing a trading program that provides the broadest flexibility and insures neutrality among

vintage or technology choices. Indeed, output-based allocation would put into practice many of the goals set forth by the enlibra principles promoted by Administrator Leavitt. The commenter noted that specifically, these principles stated that, "A clean and safe environment will best be achieved when government actions are focused on outcomes, not programs and processes, and when innovative approaches to achieving desired outcomes are rewarded." An output-based allocation method that rewards efficiency and lower emissions would be one such innovative approach. The commenter strongly urged the EPA to follow this approach in determination of the State budgets as the most equitable, and to signal support for this approach with the States in determination of the generator allocations.

One commenter (OAR-2002-0056-2843) believed that an allowance allocation budget established at this time would almost certainly unfairly discriminate among coal types and among installed APCD technologies. The commenter submitted that postponement of an equitable allocation determination until near the implementation of Phase 2 could eliminate most of the uncertainty and inequities associated with pre-mature determination.

Response:

EPA is finalizing coal adjustment factors for the purpose of establishing state emission budgets of 1.0 for bituminous coals, 1.25 for subbituminous coals, and 3.0 for lignite coals. To develop allocation ratios, EPA balanced a number of factors, including: (1) data on mercury capture by control figuration and coal type, (2) data on coal characteristics impacting Hg capture, and (3) Hg emissions by capacity. EPA believes the allocation adjustment ratios recognize that subbituminous and lignite coals have the lowest mercury capture with existing technologies, represent more emissions per capacity, and in the case of lignite also have higher mercury coal content. These adjustment factors are considered to be appropriate numbers based on the test data currently available. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Tribal Emissions Budgets, EPA, March 2005.

5.6.2 Methodology for Determining Budgets

Comment:

One commenter (OAR-2002-0056-3449) stated that estimating national mercury emissions based on sampling of coal from all coal-fired units and testing about 80 units is appropriate. However, these tests were too limited for allocations to specific states or plants. The commenter submitted that testing at more than 80 units would be needed to allocation of allowances.

Response:

EPA is finalizing a formula to be used to develop budgets for each state and Tribes for 2010 and 2018. That formula is, in essence, the sum of the hypothetical allocations to each affected Utility Unit in the State or Tribe, 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. The commenter is incorrect in the assumption that emissions data was used to develop the budget allocations. Rather, reported heat input from affected units was used to develop the allocation. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Tribal Emissions Budgets, EPA, March 2005.

Comment:

One commenter (OAR-2002-0056-4139) stated that the proposed budget is too high and would not provide for adequate reductions in Phase I. The commenter claimed EPA has exaggerated the Phase 2 reduction as well ; it would not occur by 2018. The commenter submitted the budget allocation for Michigan would not reach the national average reduction even in 2018–only 63 percent of it. The budgets were established by fuel types burned. However, the commenter believed the focus must be on needed mercury reductions. The commenter asserted the method for budget allocations must be changed to ensure public health protection.

One commenter (OAR-2002-0056-3976) submitted that the 2018 mecury allowances cause 7 of the top 10 plants and all of the top 5 to be in Texas. The commenter stated this placed an undue mercury allocation on Texas of 59,391 ounces per year compared to 5077 for New York and 0 for California.

Response:

EPA maintains that it is appropriate to base emission budgets on baseline heat input that is adjusted to reflect the ranks of coal combusted by the unit during the baseline period. It should also be noted that these allocation adjustment factors should not impact the achievement of the specific environmental goal or impact the overall efficiency of the cap-and-trade program. Allowance allocation decisions in a cap-and-trade program raise essentially distributional issues, as economic forces are expected to result in economically least cost and environmentally similar outcomes regardless of the manner in which allowances are initially distributed.

Comment:

One commenter (OAR-2002-0056-2452) noted that EPA has requested public comment on an appropriate mercury cap level for 2010-2017. The commenter requested that before EPA goes final with its proposed cap level for this time period, that the proposed cap level, state budgets, and unit-level allocations be published for public comment in a supplemental notice of proposed rulemaking (SNPR) in the Federal Register. As per the commenter's recommendation on state mercury budgets and unit allocations, all unit level allocations and state budgets could be published for comment based on the commenter's recommendation of a single mercury emission standard for all coal-fired units applied to baseline heat input (without adjustment for fuel type).

Another commenter (OAR-2002-0056-2108) noted that the proposal did not contain any State budgets for 2010, nor did it indicate when such budgets would be promulgated. According to the commenter, this is a critical piece of the program.

Response:

As discussed above, EPA maintains that it is appropriate to use coal adjustment factors for the purpose of establishing state emission budgets. EPA also maintains that the commenter has been supplied with appropriate notice and comment for the 2010-2017 emission budgets because EPA has noticed the unit allocations used to derive those budgets in the supplemental notice of proposed rulemaking. The final rulemaking includes State and Tribal emissions budgets for 2010-2017 and 2018 and after.

Comment:

One commenter (OAR-2002-0056-4891) noted that EPA has proposed a budget allowance for Texas of 1.837 tons per year for 2018 and thereafter. The commenter supported a proposed mercury emissions budget allowance for Texas of no less than EPA's proposal.

Response:

EPA has used the same methodology to determine state emission budgets as the proposed rulemaking. EPA has made some adjustments to the unit-level allocation data for the final rulemaking which as resulted in some state budgets changing for the final rulemaking. For discussion of final rule State and Tribal Budgets see Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Tribal Emissions Budgets, EPA, March 2005.

Comment:

One commenter (OAR-2002-0056-3432) observed that industrial boilers are already subject to a MACT rule which the EPA issued as final on February 26, 2004. The commenter noted with considerable interest that in the March 16, 2004 SNPR, in th units allocation table (69 FR 12435), the EPA includes Alma Bl, B2, and B3 in the listing of units with "Phase II Hg allocation(ounces)." The commenter stated that these are the same units that the EPA has otherwise identified as industrial boilers (or IBs) since they serve generators less than 25 MWe. The commenter found the inclusion of these units in the units allocation table confusing since the commenter found no explanation in the SNPR for a deviation from the prescribed definition of these combustion units. The commenter stated that EPA needs to clarify the listing of their Alma IB units.

Response:

The commenter did provide EPA with specific nameplate capacity data to determine whether they are not affected units under this program. Therefore, EPA has included they in the

unit-level allocations used to determine state emission budgets for the final rule. EPA notes that these hypothetical unit allocations to not determine applicability to the program. Rather, applicability is determined by whether a unit meets the definition of affected unit (see regulatory text of final rule, §60.4104, for full definition). If the commenter's units are determined to be unaffected units, EPA maintains that removal from the list of hypothetical unit allocations will not significant impact the state emission budget for Wisconsin.

Comment:

According to one commenter (OAR-2002-0056-3443), state budgets should be in perpetuity. A shifting state budget would make long-term planning difficult for utilities and would add significantly to the administrative burden of the rule. The commenter stated it would also discourage repowering or retirement of uncontrolled units.

Response:

EPA has established permanent state Hg emission budgets for the first (2010-2017) and second (2018 and after) phase of the program.

5.6.3 Baseline Data Used in Emission Budgets

Comment:

One commenter (OAR-2002-0056-2922) suggests that, in reference to the calculation of the baseline heat input, EPA must take steps to ensure that the heat input data for non-Title IV units are accurate. The commenter noted that in its proposal, some of the heat input data that EPA provided for non-Title IV units were incorrect.

Several commenters (OAR-2002-0056-2162, -3565) believed EPA must take steps to ensure that the heat-input data are correct so that accurate baselines can be established. One commenter (OAR-2002-0056-3565) stated that EPA should publish all heat input data and any other data it intends to use and clearly describe the methodology by which it intends to calculate both a unit's baseline and the allowances to be allocated to the unit. The commenter cannot exactly duplicate and match the proposed allowance allocation for its units with the allowances listed in the proposed rule. The commenter stated that enough data and information should be clearly provided to allow all affected sources the ability to calculate and check their individual allocations.

One commenter (OAR-2002-0056-2891) stated that EPA must address errors and omissions in its ICR database and provide a mechanism for correction of mercury unit allocations. According to the commenter, for a number of reasons, information reported to EPA and reflected in its ICR database regarding gulf coast lignite was seriously flawed. The commenter added that appropriate information regarding waste coal and its use in Southern Illinois was not reflected in the database. The commenter further stated that in addition, changes in generating unit operational circumstances have occurred since 1999. For these and other

reasons, the commenter recommended that a petition process be put in place to facilitate needed unit allocation changes.

One commenter (OAR-2002-0056-2162) noted that in its preamble to the Proposed Mercury Rules, the Agency specified that baseline heat input would be determined for each affected unit by determining the average of the three annual highest heat input values for the period from 1998 to 2002. However, based upon a review of the Agency's revised unit allocations, it appeared to the commenter that the Agency has established allocations for many of the commenter facilities based upon only one year of heat input data.

The commenter believed that the Agency's methodology for establishing unit allocations under the proposed cap-and-trade approach may rely exclusively on data collected in accordance with 40 CFR Part 75 monitoring standards. Although Acid Rain Program data may be the best available data for many electric utility steam generating units, the majority of the commenter's facilities have been exempted from the program, including its monitoring provisions, since the program's inception. The commenter's facilities generally began to monitor emissions in accordance with Part 75 requirements during 2002, pursuant to implementation of the NO_x SIP Call Rule. In fact, EPA has accepted monitoring data collected by the commenter's facilities under 40 CFR Part 60 for purposes of all other federal allocation programs, including even the initial allocation under the NO_x SIP Call Rule.

Notwithstanding the availability of more complete historic heat input data for the commenter's facilities (which the Agency utilized in the context of the NO_x SIP Call), the Agency utilized only one year of heat input in establishing a baseline value for the commenter's facilities. In fact, while the Agency identified both 2002 and 1999 heat input data for most the commenter's facilities, the Agency only utilized the 1999 data, even where the 2002 data demonstrated a higher heat input. This would pose a significant disadvantage to the commenter's facilities, which do not have the benefit of averaging the three highest years of heat input, and inexplicably have been limited to 1999 heat input data. The commenter submitted further, to the extent that the Agency has relied on heat input data that reflected an aberrational operating condition, the baseline heat input value may be inappropriately low.

For these reasons, the commenter requested an opportunity to submit complete and accurate heat input data for the years 1998 through 2002, from which the Agency could determine appropriate baseline heat input values, and mercury allocations, for the commenter's facilities.

Response:

EPA is finalizing a formula to be used to develop budgets for each state and Tribes for 2010 and 2018. That formula is, in essence, the sum of the hypothetical allocations to each affected Utility Unit in the State or Tribe, 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.

Commenters indicated inaccurate data in the hypothetical unit allocations used to determine the emission budgets, but have not pointed to specific errors or provided corrected data. Thus, EPA is unable to address the commenters claim's. EPA believes that its methodology for determining the state emission budgets is accurately described in its emission budget technical support document and in the companion spreadsheet file, both in the rulemaking docket (see Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Tribal Emissions Budgets, EPA, March 2005 and electronic spreadsheet file: Final CAMR Unit Hg Allocations.xls, which contains the unit level allocations).

The use of one years worth of data was done for non-Acid Rain units, because this was the only available data. Non-Acid Rain units in the Hg ICR inventory do not uniformly report annual heat input to EPA's Clean Air Market Division (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 (see Budget TSD for more discussion).

With regard to commenter's request to submit more appropriate data for 1998-2002, EPA notes that it requested at proposal for commenters to submit such data. For commenters who submitted such data, EPA adjusted hypothetical unit allocations accordingly. In most instances, corrections to baseline heat input data at the unit level allocation are not likely to result in significant changes to the overall State or Tribal emissions budgets. Under the model trading rule, EPA notes that States and Tribes have the authority to allocate at the unit level and commenters can submit corrected baseline heat input to the State or Tribe prior to the allocation process.

Comment:

Several commenters (OAR-2002-0056-2915, -3478, -4191) supported the 1999 coal type use as the basis for the adjustment of the baseline for establishing plant mercury allocations. Commenter OAR-2002-0056-3478 stated that this is the year upon which the 48-ton electric utility mercury emissions were based. Several of the commenters (OAR-2002-0056-2915, -4191) believed using 1999 as the fuel baseline is needed to provide certainty. The commenters added, 1999 is the only year for which EPA already has data for all the coal-fired EGUs throughout the country.

Several commenters (OAR-2002-0056-2180, -2816, -2900, -2948, -3537, -3546, -3556, -3565) stated that basing plant mercury allocations on the coal rank used in 1999 would not reflect coal type switches that have occurred since the coal rank year. One commenter (OAR-2002-0056-2180) pointed out that, therefore, units that have switched coal type since 1999 would not receive an appropriate or relevant allocation of allowances for future operation, as the allowance adjustment factor would be based on historical coal type, not the current coal type. The commenter was a joint owner of two coal units that have switched coal rank since 1999 and stated that they would be adversely affected by the proposed method for determining the allowance adjustment factor and mercury allowances. The units represented about two-thirds

of the commenter's total coal capacity. These units switched coal rank from bituminous coal to sub-bituminous coal to comply with the NO_x SIP Call. According to the commenter, using sub-bituminous coal in these units reduced the NO_x emission rate by about 50 percent. The commenter stated that switching coal type was not simply a matter of ordering a different type of coal. The commenter emphasized that to use sub-bituminous coal at its units, they made significant and necessary investments to the units' systems for coal transportation, coal handling, dust suppression, fire protection, particulate emissions control, and ash handling. The commenter stated that the coal switch qualified as a pollution control project under New Source Review regulations, and the decision to switch coal type came about long before the mercury cap and trade rule was proposed. The commenter asserted that the mercury trading rule's application of allowance adjustment factors should be revised to reflect coal type switches that have occurred since the baseline coal rank year, and especially for coal type switches that were done towards complying with Clean Air Act requirements and where the decision to switch coal type occurred prior to the proposed mercury rule. The commenter stated that for such situations, the final rule should enable the use of the adjustment factor for currently used coal. According to the commenter, this recommended revision would not affect the total number of national mercury allowances, only the allocation of the allowances among affected units, and would only have a very minor change in allowances allocated to other affected units. Another commenter (OAR-2002-0056-2948) suggested that EPA should permit units that had a significant change in their coal-type usage since 1999 to provide EPA with that information before allocations are finalized.

A third commenter (OAR-2002-0056-3537) stated that in anticipation of new regulatory requirements, two Utility Units co-owned by the commenter switched from eastern bituminous to western sub-bituminous coal to lower NO_x emissions. In 2001, the decision was made by the Corporation (and the other co-owners) to switch to sub-bituminous coal, in anticipation of imminent new regulatory requirements for Georgia. According to the commenter even though the units in question were originally designed to burn this type of coal, some engineering and design work was needed to facilitate the switch. This was started in late 2001 and construction began in early 2002, in order to fully implement the switch in 2004. The commenter stated the units began to operate fully on sub-bituminous coal at the beginning of 2004. The commenter noted if EPA uses the coal type used by each unit in 1999, however, to determine the adjustment factor, then no adjustment to these units' baseline will be made. Further, when Georgia (under CAA section 111) or EPA (under CAA section112) allocates back to these units from Georgia's mercury trading program budget, likely that same multiplier (i.e., 1.0) instead of the higher ratio for subbituminous coal would be used. The commenter submitted that the result would be a lower allocation of mercury allowances to such units than would otherwise occur had those units been given credit for the fuel that is actually being burned. The commenter believed that such units will be "short-changed," since they would not receive the amount of mercury allowances needed for the coal they are now burning–coal whose mercury emissions are by their very nature harder to control than the type combusted in 1999. The commenter claimed that such units would automatically be at a distinct competitive disadvantage vis-a-vis other units, who were fortunate enough not to have switched to a lower ranked coal since 1999. The commenter asserted that the result would be patently inequitable, in essence punishing the affected units for taking steps to comply with an important State and federal program for the control of a criteria

pollutant, by failing to allocate to them the allowances that correspond to actual coal usage. The commenter believed EPA should not allow these units to be so unfairly prejudiced. EPA should correct this inequity for those Utility Units that switched fuels for environmentally beneficial reasons, by allowing a unit that switched to a lower ranked coal for reasons other than the Mercury Rule to use the year the Mercury Rule is finalized as the year to determine the adjustment ratio to be used, both when computing State budgets and when allocating mercury allowances to units within the State. The commenter suggested alternatively, EPA could allow owners of those few units in this position to petition it (or the relevant State) for use of a different adjustment ratio that matches the real-world coal use at such units.

Several other commenters (OAR-2002-0056-2911, -3546, -3556) cited circumstances leading to fuel switches that would be inequitable to the Utility Unit. One of these commenters (OAR-2002-0056-3546) believed EPA should permit units that had a significant change in their coal-type usage in connection with mine closures or environmental purposes to provide EPA with that information before allocations are finalized so that EPA could use the adjustment factors that more accurately reflect the coal actually being used at a unit.

The other commenters (OAR-2002-0056-2911, -3556) stated that allocations of allowances based on the 1999 fuel blend would be detrimental to those units that have increased the percentage of western fuel burned, as mercury from western coal is harder to remove, therefore a larger allocation is necessary to prevent fuel bias. The commenter recommended that more recent and representative data be used to allocate allowances. The commenter believed this would ensure that allocations to the states, with units that have switched to western coal, would be done in a manner that would not to create a competitive disadvantage due to an inappropriate allocation of allowances.

One of these commenters (OAR-2002-0056-2911) included a graph showing the substantial changes to fuel blends that have occurred since 1999 due to the lower cost and compliance with the Acid Rain provisions of the Clean Air Act.

One commenter (OAR-2002-0056-3565) had seven units located at three different plants, which burned bituminous coal in 1999 but switched to sub-bituminous coal in 2000, which they continue to burn today. The commenter stated that these seven units should receive the higher heat input allocation factor 1.25 for sub-bituminous units and not the 1.0 factor for bituminous units. The commenter strongly urged EPA to use the year 2003, or even 2004, to determine coal-type usage.

One commenter (OAR-2002-0056-2816) noted that EPA proposed to use 1999 Information Collection Request (ICR) data to determine the coal-type usage patterns of units subject to regulation. The commenter stated that these data are important because they determine the factors that will be used to adjust heat input based on coal type. The commenter submitted that using 1999 data to determine coal usage patterns would result in incorrect information regarding coal use by a majority of the commenter's units, as well as the units of other companies that switched from high sulfur bituminous coals to low sulfur sub-bituminous coal during and after 1999 in order to comply with requirements for reducing SO_2 emissions for

Phase II of the Title IV Acid Rain Program. The commenter submitted that incorrect identification of the coals actually being used by these units would result in significant penalty in allocating allowances to any such unit. The commenter submitted that to more fairly and accurately represent the coal-type usage pattern for such units, EPA should implement one of the following proposals:

- EPA should permit companies with units that had a significant change in their coal-type usage during or after 1999 to provide that information to EPA before allocations are finalized. EPA should revise its coal type usage data for those units and use the adjustment factors that accurately reflect the coal actually being used at such units. EPA could limit manipulation of the factors by restricting coal-type usage data to an annual period before December 31, 2004; or

- Rather than using the ICR data to set allowance allocations, EPA should use the most recent publicly available fuel data (2004) such as that provided to the Department of Energy on Forms 423 or 906. These data specify the type of fuel used at each coal-fired power generating facility on a current basis.

One commenter (OAR-2002-0056-2900) noted the proposed 2018 allowance allocations are based on the coal burned at the affected units during the baseline period, which is the average of the three years of highest heat input from 1998-2002. EPA proposed it would use this same methodology to set 2010 allowance allocations. The commenter stated that subsequent to the proposed baseline period of 1998-2002, many coal-fired EUSGUs have switched or are in the process of switching from the use of bituminous coal to sub-bituminous coal to meet the requirements of other programs. The commenter believed EPA must allow such units the option of establishing a different baseline for allowance allocations. According to the commenter, failure to do so would result in a highly inequitable system that severely penalizes units that recently have switched to lower sulfur coal.

For units that switched or partially switched from bituminous to sub-bituminous coal following the proposed baseline period of 1998-2002, the commenter urged EPA to consider an adjustment when establishing the 2010 cap and to revise the proposed 2018 allocations. The commenter suggested this could be accomplished by allowing units to choose an alternative three-year baseline that encompasses the switch. For units that only partially switched to sub-bituminous coals, the heat input could be proportioned to reflect the amount of sub-bituminous and bituminous coal burned during the revised baseline period when any blending occurred, similar to the MACT provision allowing mercury emissions to be weighted proportionally by fuel type when blending.

The commenter understood that, if EPA establishes a cap in 2010, then the Phase I allowance allocations would be included in the final rule. The commenter noted that this would not allow units that have switched to sub-bituminous coal to select an alternative baseline period. Therefore, for Phase I, the commenter proposed that EPA deal with any additional allowance allocations to alternative baseline units through the establishment of an allowance set-aside. For Phase II, the commenter proposed that EPA revise the allowance allocations once units have

submitted their alternative baseline to EPA. The commenter further recommended that alternative baseline units be required to use the lower heat input from the 1998-2002 time period or the alternative baseline period. Specifically, units would demonstrate an alternative baseline for purposes of determining the coal type on which their Phase II allowance allocations should be based and their eligibility for the Phase I alternative baseline allowance set-aside. However, for determining heat input, the commenter recommended the unit would be required to use the lower of the baseline selected by EPA from the 1998-2002 time frame (EPA used the average of the highest three years of heat input from the 1998-2002 time frame in determining the proposed Phase II allowance allocations for the SNPR) or the alternative baseline. The commenter believed this requirement would prevent units from gaming the system.

The commenter did not have a specific recommendation as to the size of the alternative baseline allowance set-aside that would be appropriate for Phase I but believed that EPA could readily determine this information by sending out a request and reopening the comment period on this narrow issue to determine which units have switched to sub-bituminous coal or are in the process of switching. The commenter submitted the responses would provide EPA with a reasonable estimate of the amount of allowances needed for the set-aside.

Response:

EPA agrees with commenters that 1999 coal type is appropriate for the use as the basis for the adjustment of the baseline for establishing plant mercury allocations. 1999 is the only year for which EPA already has data for all the coal-fired power plants throughout the country, is the year upon which the 48-ton electric utility mercury emissions estimate was based, and the emissions EPA examine in developing its coal adjustment factors.

EPA is finalizing a formula to be used to develop budgets for each state and Tribes for 2010 and 2018. That formula is, in essence, the sum of the hypothetical allocations to each affected Utility Unit in the State or Tribe, 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. Commenters did not provide data that indicated how coal switching since 1999 would impact, if at all, the state emissions budgets.

Under the model trading rule, EPA notes that States and Tribes have the authority to allocate at the unit level and they can use a different baseline year for coal type used to determine unit level allocations.

Comment:

One commenter (OAR-2002-0056-3431, -3400) stated that upon review of Appendix B to the Preamble (Unit Allocations) and EPA's April 5, 2004 memorandum to the Docket titled "Revisions to Unit Level Allocations and State Emissions Budgets for the Proposed Mercury Trading Rulemaking" it appeared that the commenter's Warrior Run allocation (21 ounces) was

incorrect and should be greater. (The commenter noted that Warrior Run was a 180 MW coal-fired power plant located in Maryland.) The commenter noted that in the April 5, 2004 memo, EPA stated that the figures in the spreadsheet that accompanied the memo would replace the hypothetical unit allocations in Appendix B and the state emission budgets in the regulatory text of the Supplemental Rulemaking. The commenter stated that if they are interpreting the spreadsheet correctly, EPA's spreadsheet showed zero (0) heat input for the plant trom 1998 to 2001 and 15,587,456 mmBtu in 2002. The correct heat input (mmBtu) at Warrior Run trom coal was as follows:

1999	2000	2001	2002	2003
1,128,625	14,890,200	15,495,345	15,222,786	15,579,265

The commenter stated that start-up operations commenced in 1999, explaining the low heat input for that year. The commenter believed that because EPA did not record any heat input for 1999 to 2001, the baseline data that EPA used to calculate the commenter's allocation was probably incorrect. The commenter requested that EPA verify its heat input information for Warrior Run and update the information and calculations used to calculate Warrior Run's allocations and Maryland's state emissions budgets.

The commenter observed that as provided for in the Supplemental Notice of Proposed Rulemaking, the other plants' allowance allocations were based on their proportion of the total state's heat input. The commenter stated for example, the combined heat input for the three units at Dickerson Station was approximately 11 percent of the total Maryland heat input, and the station was allocated 647 allowances which was 11 percent of the total Maryland 2018 mercury allocation. Based on the commenter's heat input figures above, Warrior Run's heat input was approximately 5 percent of the total Maryland heat input and therefore the commenter should receive roughly 5percent of the total Maryland budget, or approximately 296 allowances. The commenter stated that however, the allocation for Warrior Run in the April 2004 memo was only 21 allowances–0.35 percent of the total Maryland budget instead of the 5percent that should have been provided.

The allocation issue was of great concern to independent power producers (IPPs) such as the commenter. The commenter stated that passing through increased costs to comply with new environmental regulation in rates could rectify shortfalls in allowance allocations for power plants owned by traditional utilities; however, IPPs would not have this luxury and must absorb such increased costs against the plant's bottom line.

Response:

EPA updated the heat input data for 1 plant based on commenter input. EPA data was missing heat input for the AES Warrior Run plant in Maryland for the years 1998-2001. The data submitted by the commenter is highlighted in the heat input data spreadsheet available in the docket (see electronic spreadsheet file: Final CAMR Unit Hg Allocations.xls, which contains the unit level allocations).

5.6.4 Tribal Emission Budgets

Comment:

Several commenters (OAR-2002-0056-2010, -2118, -2380, -3413, -3469, -3549, -3550, -3551) opposed cap and trade, but stated that if EPA adopts this approach the rule must make provisions for tribal allowances.

One commenter (OAR-2002-0056-3469) stated that in the event a cap-and-trade program is implemented by the EPA to reduce SO_2, NO_x or mercury, future tribal energy development projects and existing power plants burning Indian country coal that has a higher sulfur content than SPRB coal, i.e., more than 1.2lb SO_2/mmBtu, will be allocated allowances (a) as ultimately determined by EPA for NO_x and mercury and (b) as currently scheduled under Title IV for SO_2 or otherwise under a separate CAIR program, depending on its structure. These new projects and plants would be permitted to use these allowances according to the following formula:

- 1 allowance for 2 tons of SO_2-effective immediately through 12/31/05
- 1 allowance for 3 tons of SO_2-effective 1/1/06 forward
- 1 allowance for 2 tons of NO_x-effective with CAIR implementation
- 1 allowance for 2 ounces of Mercury-effective with CAIR and Mercury Rule implementation

The commenter noted that the SO_2 formula above would only apply to noncompliance coal (i.e. greater than 1.21b SO_2/mmBtu). The commenter believed the accelerated schedules for the SO_2 formulae above are justified given that the mere announcement of the CAIR proposal is having real and immediate impacts on the Title IV SO_2 allowance market with real and current impacts on Indian country coal. (Allowance prices have already increased by 80 percent largely due to announcement of the proposal). The commenter submitted that granting these preferential allowance ratios will have no negative impact on national emissions. SO_2 emissions at plants using Indian country coal will not increase emissions nationally as these plants are already scrubbed and compliant with NSPS. The commenter also noted the SO_2 ratio is based upon the greater amount of sulfur content in Montana Indian country coal when compared to SPRB coal. EPA intends to increase the market price of Title IV allowances by reducing available supply, thus providing economic justification for power plants to retrofit emission control technology. The commenter stated that by intertwining the CAIR with Title IV, the proposal would increase SO_2 costs for all plants across the country, not just in the 29 states and D.C. The commenter believed that volatility in the SO_2 allowance market could drive changes in fuel choices at clean plants using Indian coal, or could even cause plants to shut down, depriving the tribes of coal sales royalty and tax revenues, employment, and other economic benefits they currently rely on to sustain their nations.

Response:

EPA has provided budgets to tribes in the final rule that have existing sources on their land. Requirements for new tribal sources under CAMR are discussed in the preamble.

EPA understands and is sympathetic to the economic situation of the specific tribe's comments. EPA staff and officials have met with one of the commenters regarding their concerns regarding the CAIR rulemaking, and considered the comments and proposals put forth by the commenters. EPA's analysis of the Crow tribe's economic situation, and discussions with the commenters, suggest that the Tribe should not experience adverse economic impacts as a result of the NO_x caps under CAIR. Rising SO_2 prices, however, may lead to the erosion of the competitive advantage currently held by coal from Absaloka mine, and could potentially force the mine to shut down. However, the erosion of this competitive advantage is not a direct effect of CAIR, as the price advantage held by Absaloka coal is likely to disappear under title IV alone.

The EPA has determined that we can not implement the commenters recommendation for the following reasons: The proposed Hg allowance retirement ratios would undermine both the environmental certainty and economic stability of the cap-and-trade program. If EPA were to allow power plants burning Indian country coal, and future tribal energy development projects to retire allowances at a less than one to one ratio, the certainty of the cap level, and the resulting knowledge of the value of an allowance would be jeopardized. This lack of certainty about the cap is unacceptable for a cap and trade program, which function most successfully when environmental and economic certainty have been established.

Comment:

Several commenters (OAR-2002-0056-2380, -3413, -3457) noted that Tribal organizations opposed cap and trade, but asked EPA to include these provisions. Commenter OAR-2002-0056-2380 suggested: (1) Tribes should be included where they are omitted. (2) Restrict trading. EPA should set an appropriate ceiling for the number of credits any source may hold and use at a given time. (3) Require a higher trading ratio for facilities with high emissions to encourage sooner installation of controls. It should cost more to buy credits than to not install controls. Commenter OAR-2002-0056-3457 recommended that any allowance system forbid trading and require allowances to expire or be discounted over time.

Response:

In the final rule, EPA has established Hg emission budgets for tribes with existing sources. Requirements for new tribal sources under CAMR are discussed in the preamble. EPA believes that a cap-and-trade program for Hg will provide for an efficient means of achieving the necessary level of emissions reductions. Allowing for trading maximizes the cost-effectiveness of emissions reductions. Sources that can reduce emissions most cheaply will do so, and sell any remaining allowances to sources that cannot. Sources have an incentive to endeavor to reduce their emissions below their allowance allocation; if they can do so cost-effectively, they may then sell their excess allowances on the market. In practice, the

sources that can reduce emissions cost-effectively under a cap-and-trade program are the largest (and frequently high emitting) sources.

Comment:

Several commenters (OAR-2002-0056-2380, -3413) noted that the tribal authority rule allows tribes to adopt parts of air programs without being subject to deadlines or other requirements imposed on states. The commenters submitted the proposed rule should include a mechanism for tribes to enter the cap-and-trade program if and when they want. At minimum, tribes need allocations for plants already located on Indian land or planning to do so. The commenters also submitted that in absence of adequate resources for a tribe to enter the program (i.e., inability to develop and implement a tribal implementation plan), EPA should develop a Federal Implementation Plan for them.

Response:

EPA has provided budgets to tribes in the final rule that have existing sources on their land. The requirements of tribes under CAMR are discussed in the preamble.

Comment:

One commenter (OAR-2002-0056-3469) stated that if CAA provisions do not permit an exemption for new plants in Indian country, the EPA should make available to developers or new consumers of Indian country energy a pool of SO_2, NO_x and mercury allowances equal to 5 percent of all allocations at set prices. The commenter suggested that these prices would be established as follows:

- 50 percent of the mercury price modeled by EPA;
- Average SO_2 allowance price 2000-2003; and
- 50 percent of the NO_x price modeled by EPA.

Response:

EPA has allocated allowances to States and tribes on the basis of heat input and coal type. States have the authority to determine how to allocate allowances to sources within the State. Allocations to States and tribes are discussed in section IV of the preamble.

Comment:

Several commenters (OAR-2002-0056-1961, -3469) recommended that new Tribal plants be exempted from the requirement to purchase allowances as long as they have NSPS Subpart Da technology operational when they initiate operations and they adhere to monitoring and reporting requirements, demonstrating continuous compliance. One commenter

(OAR-2002-0056-3469) submitted given that lignite units and the small number of new plants that could be built by the Tribes will contribute a minute amount of mercury to the global pool, exempting new plants will not materially affect any caps adopted by the EPA. One commenter (OAR-2002-0056-1961) added that if EPA does not exempt them, EPA should make an energy pool available for mercury allowances equal to 5 percent of all allocations at set prices (50 percent of mercury prices modeled by EPA). This will help tribes who have developed their coal reserves.

Response:

In the final CAMR, new sources will be covered under the Hg cap of the trading program, and will be required to hold allowances equal to their emissions. EPA maintains that is essential to include new sources under the cap to ensure that environmental goal of reducing mercury emission is achieved. With new sources under the cap, the environmental goal continues to be achieved despite future growth in the electric power sector, as older coal-fired generation is retired and replaced new coal-fired generation. Requirements of new tribal sources under CAMR are discussed in the preamble.

5.7 ALLOCATION METHODOLOGY

5.7.1 Allocation Mechanisms

Comment:

One commenter (OAR-2002-0056-2860) recommended that a parallel allowance allocation methodology similar to that used under the IAQR should be used. The commenter believed this would promote consistency among programs.

Response:

EPA agrees with commenter and has provided an example unit allocation methodology for the Hg model trading rule as consistent as possible to the CAIR NO_x allocation methodology.

Comment:

One commenter (OAR-2002-0056-1608) believed that in order to establish consistency across the country, the EPA should develop the model trading rules in a way that maximizes appeal to all of the states affected. The commenter however urged the EPA to assure that any allocation methodology developed for mercury allowances under a trading program does not penalize sources that are already achieving co-benefit reductions through the operations of existing control equipment.

Response:

EPA believes its example allocation methodology should appeal to all states. EPA also maintains that coal adjustment factors for existing units address commenters concerns with regard to co-benefit reductions.

Comment:

Several commenters (OAR-2002-0056-2830, -2835, -2915, -3440, -3469, -3478, -3546, -4191, -4891) stated that allowances should be allocated only to affected EGUs. Four of the commenters (OAR-2002-0056-2915, -3440, -3478, -4191) explicitly stated that mercury allowances under the mercury rule should be allocated to coal-fired EGUs only.

Response:

The final CAMR requires reductions from coal-fired power plants and as such States can only allocate to these affected units.

Comment:

One commenter (OAR-2002-0056-2180) stated that allowance allocations should be periodically updated to reflect changes in capacity utilization (capacity factor), unit retirements, commencement of operation of new units, and changes in coal rank. The commenter suggested that an appropriate first update might be when Phase II of the cap comes into effect, with at least a three-year lead time for beginning the updated allocation. Thereafter, allowances could be allocated only for specific future periods, e.g. 5 to10 years.

Response:

Under its example allocation methodology, EPA has finalized for the model rule a "modified output" approach. This example method involves input-based allocations for existing coal units (with different ratios based on coal type), with updating to take into account new generation on a modified-output basis. It also utilizes a new source set-aside for new units that have not yet established baseline data to be used for updating.

Under the EPA example method, existing units as a group will not update their heat input. This will eliminate the potential for a generation subsidy (and efficiency loss) as well as any potential incentive for less efficient existing units to generate more. This methodology will also be easier to implement because it will not require the updating of existing units' baseline data. Retired units will continue to receive allowances indefinitely, thereby creating an incentive to retire less efficient units instead of continuing to operate them in order to maintain the allowance allocations. Moreover, new units as a group will only update their heat input numbers once–for the initial 5-year baseline period after they start operating. This will reduce any potential generation subsidy and be easier to implement, because it will not require the

collection and processing of data needed for regular updating. See preamble for further discussion of example methodology.

This methodology is offered simply as an example, and individual States retain full latitude to make their own choices regarding what type of allocation method to adopt for Hg allowances and are not bound in any way to adopt the EPA's example.

Comment:

Several commenters (OAR-2002-0056-2862, -2911, -2922, -2948, -3546, -3556, -3565) supported permanent mercury allowance allocations. One commenter (OAR-2002-0056-2948) believed permanent allocations of mercury allowances would provide units with the greatest amount of certainty, would provide units with an incentive to improve energy efficiency, and would require fewer resources to administer than an updated allocation system. Several commenters (OAR-2002-0056-2911, -3556) believed that such a system would provide units with certainty regarding their allowances, facilitating planning for the implementation of controls and turnover of the generating fleet - all of which would work towards the reduction of mercury emissions while maintaining the reliability of the power supply and the integrity of the grid.

One commenter (OAR-2002-0056-2862) stated that a permanent allowance allocation would provide certainty and aid in planning. The commenter added that a necessary part of a permanent allocation scheme would be to include a new source set aside. The commenter believed a permanent allocation approach coupled with a new source set aside would be less complicated than EPA's proposed updating approach and would provide units with the greatest amount of certainty while providing a mechanism for new sources to receive allowances.

The commenter (OAR-2002-0056-2721) supported free distribution of allowances that are permanently assigned to the affected unit. The commenter stated that allowing a periodically (5 years in EPA example) allocation methodology that would incorporate new units would cause uncertainty in planning for environmental compliance strategies. The commenter believed that allowances should be issued on a heat-input basis using the established baseline.

Response:

As discussed in the final rule preamble, under its example allocation methodology, EPA has finalized for the model rule a "modified output" approach. This example method involves input-based allocations for existing coal units (with different ratios based on coal type), with updating to take into account new generation on a modified-output basis. It also utilizes a new source set-aside for new units that have not yet established baseline data to be used for updating. EPA is offering States flexibility regarding allocation of allowances to sources. This includes the flexibility to create new source set-asides and/or to issue allowances on a permanent basis. As discussed in the preamble, EPA does not believe these flexibilities impact the total cost or environmental benefits of the overall rule.

The commenter is also inconsistent in supporting a new source set-aside while condemning programs that adjust allowance allocations periodically. A new source set-aside (where unused allowances are returned to existing sources) effectively adjusts allocations periodically.

Comment:

One commenter (OAR-2002-0056-2721) recommended that the allocations of allowances are based on the baseline heat input.

Response:

As discussed in the final rule preamble, under its example allocation methodology, EPA has finalized for the model rule a "modified output" approach. This example method involves heat input-based allocations for existing coal units (with different ratios based on coal type), with updating to take into account new generation on a modified-output basis. It also utilizes a new source set-aside for new units that have not yet established baseline data to be used for updating. EPA is offering States flexibility regarding allocation of allowances to sources.

Comment:

One commenter (OAR-2002-0056-2181) agreed with EPA that there are significant benefits associated with an allocation method that allows for updating and felt that the rolling annual updating system, determining allocation for a single control period six years in advance, would be a reasonable time period (given the approximate amount of time required to permit and construct a coal-fired power plant) and one that the commenter would encourage States to adopt. The commenter submitted however, that the updating approach has one major flaw in that the initial allocation baseline does not change over time. This means that existing plants would continue to receive allowances in future years, even if they are shut down. On the other hand, new plants would receive allocations forever based on their initial years of operation, which could be significantly less than their ultimate operating levels due to operation and competitive limitations. The commenter believed strongly that an updating mechanism with responsive adjustments that would reflect the actual operation both in the near term and future years is the appropriate method that EPA should adopt.

Response:

Under the EPA example method, existing units as a group will not update their heat input. This will eliminate the potential for a generation subsidy (and efficiency loss) as well as any potential incentive for less efficient existing units to generate more. This methodology will also be easier to implement because it will not require the updating of existing units' baseline data. Retired units will continue to receive allowances indefinitely, thereby creating an incentive to retire less efficient units instead of continuing to operate them in order to maintain the allowance allocations. Moreover, new units as a group will only update their heat input numbers once–for the initial 5-year baseline period after they start operating. This will reduce

any potential generation subsidy and be easier to implement, because it will not require the collection and processing of data needed for regular updating. See preamble for further discussion of example methodology.

Comment:

One commenter (OAR-2002-0056-2547) supported EPA's requirement that all states adopt the "hypothetical" hybrid allowance allocation approach it describes in the preamble of the Supplemental Rule. The commenter submitted that since many facilities are exploring the use of Powder River Basin coals to meet reduced SO_2 emission requirements of the proposed CAIR rule, the mercury allocation method should be structured so as not to disadvantage units that switch to this higher mercury content fuel after promulgation of the mercury rule. The commenter believed options to consider would be not using adjustment factors at all, or if a facility switches fuels between the three listed fuel types–bituminous, sub-bituminous, and lignite, that the facility notify the state agency requesting additional allowances be allocated (or forfeiting allowances where appropriate) based upon the difference between the average heat inputs calculated in 60.4142(a)(1)(i)(A-C) for the fuel type for which the allocations were initially determined and for the new fuel type. The commenter stated this should be done in the spirit of promoting multi-pollutant emission reduction, and to aid in achieving the goals of the CAIR.

Response:

As discussed in the final rule preamble under EPA's example allocation methodology, EPA is finalizing that if states want to have allocations reflect the difficulty of controlling Hg, they might consider multiplying the baseline heat input data by ratios based on coal type, similar to the methodology used to establish the State Hg budgets in today's final rulemaking. In today's rulemaking for the purposes of establishing State budgets, EPA is using the coal adjustment factors of 1.0 for bituminous coals, 1.25 for subbituminous coals and 3.0 for lignite coals. In this example allocation methodology for States, EPA is also using these adjustment factors. EPA is offering States flexibility regarding allocation of allowances to sources. This includes the flexibility to not use coal adjustment factors.

Commenter:

The commenter (OAR-2002-0056-2181) believed that in its discussions of allowance allocation methodology, the EPA argued, "allowance allocation decisions in a cap and trade program largely reflect distributional issues, as economic forces would be expected to result in economically efficient and environmentally similar outcomes." The commenter disagreed with this conclusion, and believed that allocation choices could have a significant impact on economic and environmental outcomes. The commenter claimed that several studies supported this position and discussed the potential economic "co-benefits" of an output allocation standard. For example, a study by the Northeast-Midwest Institute concluded that an output-based allocation standard could "advance an array of innovative technologies that would offer enormous potential to improve efficiency and enhance the environment." Likewise, a policy

report by the Pew Center for Climate Change concluded that an output-based allocation standard "could significantly affect the ability of new, highly efficient generation technologies to enter the market." Conversely, the Report also concluded that input allocation would "put new investments in clean technologies at a competitive disadvantage."

The commenter noted that the allocation approach recommended by the EPA would be a hybrid approach that would include some of the desirable components but would be lacking in other areas. EPA first recommended that existing sources follow an input-based system with different allocation ratios based on coal-type. Next, it recommended accommodating new sources through updates to the allocation on a modified output basis, without differentiating between coal types. The commenter welcomed the second approach that EPA selected for new sources as a step towards a full output-based allocation system. The commenter believed that output-based allocation would be the appropriate method for all sources, new and existing. While the commenter appreciated that the hybrid is an attempt to introduce a compromise approach, the commenter believed the result would perpetuate a disturbing trend toward developing two sets of environmental rules within the nation's power sector - one for existing power sources and one for new sources. Such a two tiered system not only would create inequities among competitors, it would send market signals that may, in the long run, lead to unintended consequences to market structures within the power sector such as favoring existing generators over new entrants and regulated utilities over independent producers.

Several commenters (OAR-2002-0056-3437, -4139) recommended that allowances be set based on energy output. Commenter OAR-2002-0056-3437 stated that would reward and encourage efficiency. Similarly, Commenter OAR-2002-0056-4139 submitted an energy output model would reward conservation and renewable energy sources and encourage cleaner technology development.

Response:

As discussed in the final rule preamble, under its example allocation methodology, EPA has finalized for the model rule a "modified output" approach. This example method involves heat input-based allocations for existing coal units (with different ratios based on coal type), with updating to take into account new generation on a modified-output basis. It also utilizes a new source set-aside for new units that have not yet established baseline data to be used for updating.

The EPA believes that allocating to existing units based on a baseline of historic heat input data (rather than output data) is desirable, because accurate protocols currently exist for monitoring this data and reporting it to EPA, and several years of certified data are available for most of the affected sources. EPA expects that any problems with standardizing and collecting output data, to the extent that they exist, can be resolved in time for their use for new unit calculations. Given that units keep track of electricity output for commercial purposes, this is not likely to be a significant problem.

EPA is giving States flexibility with regards to the allocations of the its Hg budgets to sources. EPA notes that its example "modified output" allocations approach incorporates key aspects of an output based updating system and provides incentives for efficient new units. Additionally, EPA reiterates that use of output based allocation methodologies, if not updated, do not provide incentives for behavior or for new generation. They only provide a one-time transfer amongst existing sources.

Comment:

One commenter (OAR-2002-0056-3443) stated that the model rule lays out a rational program for periodic redistribution to individual sources. The commenter suggested that the initial allocation period be extended from 5 to 8 years since that would align with the 2018 Phase II compliance date. This would avoid an unnecessary reallocation prior to the 2018 Phase II compliance date. The commenter noted that the model rule proposed that allocations after the initial allocation period be on an annual basis using the original baseline heat inputs for existing units. For new units, these allocations would be based on the average of the high three year heat inputs (calculated from generation and an 8000 Btu/kwh heat rate). The commenter believed that a proposal with an 8-year initial allocation would provide a sufficient planning horizon for responding to changes in allocations. In the same vein, the commenter supported EPA's proposal to make allocations in perpetuity to retired units as it would provide owners an incentive to retire higher-emitting sources, creating a multi-pollutant (SO_2, NO_x and Hg) reduction benefit.

Another commenter (OAR-2002-0056-3444) stated to ensure that companies are able to recover investments made in control equipment and use of clean technologies, the commenter believed the initial allocation of allowances should be fixed for the existing sources for the period from 2010 until 2020. The commenter stated that the certainty associated with control equipment and construction investment decisions rely on a source's ability to realize anticipated allowance excesses to generate revenue required for those investments. The commenter maintained that by allocating on a 10-year basis EPA will maintain a minimal level of certainty in Utility Unit investments and also provide a mechanism for mercury allowances to encourage new coal fired Utility Unit entrants. The commenter believed that maintaining fuel flexibility is key to the security and reliability of the electrical grid and national energy supply.

One commenter (OAR-2002-0056-4132) stated that EPA must provide allocations, which align with the long-term nature of the emission control system investments. The commenter submitted the strategic and financial planning process involved with the industry installing billions of dollars of new pollution control equipment would be very complex. The commenter added that forecasting the value of emission allowances (sale or purchase) would be difficult. The commenter believed that if there is no certainty in the number of allowances provided in later years, the economic analysis for such projects becomes speculative.

The commenter strongly encouraged that EPA allocate mercury emission allowances for a time period that would align with the economic considerations of the air pollution control equipment required for this air quality improvement. The commenter submitted a perpetual

allocation consistent with the current Clean Air Act SO_2 allocation would be appropriate and necessary for utilities to determine the proper investment strategy. The commenter also submitted that early reduction credits should be awarded and could be allocated for a lesser time period. The commenter also believed the cap and trade system should not be subject to flow control. The commenter stated flow control would greatly reduce incentives for early reductions and hinder economic analysis.

Response:

As discussed in the final rule preamble, under its example allocation methodology, EPA has finalized for the model rule a "modified output" approach. Under the example method, allocations are made from the State's Hg budget for the first five control periods (2010 through 2014) of the model cap-and-trade program for existing sources on the basis of historic baseline heat input. The allowances for 2015 and later will be allocated from the State's Hg budget annually, six years in advance, taking into account output data from new units with established baselines (modified by the heat input conversion factor to yield heat input numbers). EPA believes this 5 year period provides enough certainty and planning time horizon.

Comment:

One commenter (OAR-2002-0056-2267) noted that EPA discussed whether allocations should be based on baseline heat input or baseline generating output under the cap-and-trade approach. 69 FR 12408. The commenter objected to a strict output-based allocation method. The commenter submitted that the smaller boilers and generators owned and operated by municipalities generally are less efficient in terms of energy output per heat input than the large boilers and generators operated by the large utilities. The commenter believed municipal power generators would be placed at an additional competitive disadvantage by the budgets being set on this basis. Adding this to the disadvantage of a smaller customer base over which to spread the emission control costs, municipal power generators would face multiple competitive disadvantages relative to large electric utilities.

Ensuring that new units have fair access to allowances was a concern for the commenter (OAR-2002-0056-2068). In concert with the EPA's "example methodology," the commenter suggested allocations be determined according to the baseline heat input of affected units. As outlined in the Supplemental Notice, initial allocations for existing sources should be made for the first five control periods at the start of the program on the basis of heat input and take into consideration coal type. After the first five years, the budget should be distributed on an annual basis, taking into account data from new units. The baseline heat input for units should be determined by averaging the three highest heat input years out of a five-year period, and allowances should be reallocated after each subsequent five-year period.

Response:

As discussed in the final rule preamble, under its example allocation methodology, EPA has finalized for the model rule a "modified output" approach. This example method involves

heat input-based allocations for existing coal units (with different ratios based on coal type), with updating to take into account new generation on a modified-output basis. It also utilizes a new source set-aside for new units that have not yet established baseline data to be used for updating.

Comment:

One commenter (OAR-2002-0056-2862) stated that allocations to retired units should be permanent. The commenter noted that EPA's definition of the baseline for calculating cap and trade emission allowances does not address the issue of how to treat units retired since the 1998-2002 proposed baseline period (69 FR 4703 and proposed 40 CFR 60.4105 of the SNPR). The commenter submitted that treatment of retired units is, however, very important. The commenter's position was that units retired since the baseline period should receive budget allowances. The commenter believed if allocations were not made to retired units, the rule effectively would discourage utility system modernization and penalize environmental improvement efforts.

The commenter stated ideally, EPA's rules should provide incentives for utilities to retire existing coal-fired generating plants and replace them with plants that are more efficient and equipped with state-of-the-art environmental controls. At a minimum, utilities that retire units that were operating during the baseline period should not be penalized. The commenter explained this means that owners should be allowed to hold allowances for retired units that were operating during the baseline period, and be able to apply those allowances as eligible emission currency in the cap-and-trade program. The commenter concluded that a permanent allocation system would ensure that retired units retain their allowances.

One commenter (OAR-2002-0056-4139) stated that future allocations should be set at less than the shutdown facility if that facility is replaced. The replacement facility should meet a new source limit to emit less mercury than the shutdown plant it replaced. The commenter submitted that if permitting and construction is not begun in a specified reasonable time, there should be a decrease over time in the allocation for the shut down declining to zero. The commenter added the overall state budget should also be decreased as described.

Response:

As discussed in the final rule preamble, under its example allocation methodology, EPA is finalizing January 1, 2001 as the cut-off on-line date for considering units as existing units. Under the EPA example method, existing units as a group will not update their heat input. This will eliminate the potential for a generation subsidy (and efficiency loss) as well as any potential incentive for less efficient existing units to generate more. This methodology will also be easier to implement because it will not require the updating of existing units' baseline data. Retired units will continue to receive allowances indefinitely, thereby creating an incentive to retire less efficient units instead of continuing to operate them in order to maintain the allowance allocations.

Comment:

One commenter (OAR-2002-0056-2519) encouraged EPA to incorporate a provision to update allowance allocations to reflect changes in electricity generation. The commenter offered for example, the West is one of the fastest growing regions of the country, and the increasing population growth will mean increased electricity demand. In order to keep coal as a viable option for such new generation, the allowance allocation should be updated periodically to match increases and shifts in power generation at existing sources and new sources. Toward that end the commenter recommended that the allowance allocation should be updated every five years.

Response:

As discussed in the final rule preamble, under its example allocation methodology, EPA has finalized for the model rule a "modified output" approach. This example method involves heat input-based allocations for existing coal units (with different ratios based on coal type), with updating to take into account new generation on a modified-output basis. It also utilizes a new source set-aside for new units that have not yet established baseline data to be used for updating.

Comment:

One commenter (OAR-2002-0056-2267) requested that EPA make a change to the rule to allocate additional allowances to the entities in recognition of the their foresight and progressive in investment in hydroelectric power (or other green power) when cheaper energy choices could have been made. As it stood, the commenter's municipality ultimately would be penalized, rather than rewarded, for its early focus on reducing emissions from its power generation system. To address this situation, the commenter requested that the budget allocation be based on potential or projected heat input rate for entities such as the commenters. By granting this request, EPA would ensure that the commenter's and other similar entities have enough allowances to provide reliable power generation at an affordable price. As an alternative solution, the commenter requested that EPA provide in its model trading program rules for the use of a different time period to calculate baseline heat input for situations described above. The commenter cited precedence under the Clean Air Act for substitution of baseline data when a baseline period is not representative of normal source operation. See 40 CFR 52.21(21)(ii) (NSR rules). The commenter stated EPA has recognized that it should have discretion to allow the use of a different time period upon a determination that it is more representative of normal source operation. The commenter recommended that EPA should exercise similar discretion in this case.

Response:

State are required to achieve the mercury reduction requirements by reducing Hg emissions from coal-fired power plants. States are welcome to use set-asides (size determined by the State) for new units and any special policy objectives - such as promoting energy

efficiency or renewables. The States, rather than this regulation can decide the best way to incorporate renewable incentives.

5.7.2 Baseline Period for Allocations

Comment:

One commenter (OAR-2002-0056-3478) supported the use of the average of the highest three-year heat inputs achieved during the five-year period of 1998 to 2002 as the baseline for establishing plant mercury allocations.

Several commenters (OAR-2002-0056-2867, -2922, -2948, -3437, -3565) noted the proposed calculation of the baseline heat input by "using the average of the three highest heat inputs of the period 1998 to 2002" and suggested using a more current period. Two of the commenters (OAR-2002-0056-2922, -2948) suggested using the average of the three highest heat inputs of the period 1999 to 2003. These commenters believed this approach would use a period that would be closer in time to the commencement of the trading program under EPA's proposal and still would avoid opportunities to affect the baseline through prospective actions. One of the commenters (OAR-2002-0056-3565) strongly urged EPA to use the average of the three highest heat inputs of the period 1998 to 2002.

One commenter (OAR-2002-0056-2867) recommended that EPA consider using the average heat-input of the highest of three years from the period which begins six years prior to the implementation of the cap (2004 if the cap takes effect in 2010 as proposed or 2009 if the cap takes effect in 2015 under the commenter's recommended program) to account for growth in electricity demand, changes in the generation fleet, the inherent variability in heat input levels for individual units, and for weather and demand induced variability.

One commenter (OAR-2002-0056-3437) noted that EPA did not mention updating the baseline heat input based on more recent years of operation. The commenter stated that the rule would use the same baseline throughout time. The commenter believed this would help in having to track annual operating data, but it was not clear to the commenter if this would increase or decrease a unit's allowances if the heat input data was update. The commenter noted EPA says this is preferable because it would eliminate a potential generation subsidy and an incentive for less efficient generation. The commenter stated that EPA should use an output based emission rate to address efficient generation and a system that would use updated heat input to more accurately reflect industry changes.

Response:

For existing units under the model trading rule, EPA is using the average of the highest three-year heat inputs achieved during the five-year period of 2000 to 2004 as the baseline for establishing plant mercury allocations. EPA proposed January 1, 2001, cut-off on-line date for considering units as existing units. The cut-off on-line date was selected so that any unit meeting the cut-off date would have at least five years of operating data, i.e., data for 2000 through 2004.

EPA is concerned with ensuring that particular units are not disadvantaged in their allocations by having insufficient operating data on which to base the allocations. EPA believes that a 5-year window, starting from commencement of operation, gives units adequate time to collect sufficient data to provide a fair assessment of their operations.

As discussed in the final rule preamble, under its example allocation methodology, EPA has finalized for the model rule a "modified output" approach. This example method involves heat input-based allocations for existing coal units (with different ratios based on coal type), with updating to take into account new generation on a modified-output basis. It also utilizes a new source set-aside for new units that have not yet established baseline data to be used for updating.

The EPA believes that allocating to existing units based on a baseline of historic heat input data (rather than output data) is desirable, because accurate protocols currently exist for monitoring this data and reporting it to EPA, and several years of certified data are available for most of the affected sources. Under the EPA example method, existing units as a group will not update their heat input. This will eliminate the potential for a generation subsidy (and efficiency loss) as well as any potential incentive for less efficient existing units to generate more. This methodology will also be easier to implement because it will not require the updating of existing units' baseline data. Retired units will continue to receive allowances indefinitely, thereby creating an incentive to retire less efficient units instead of continuing to operate them in order to maintain the allowance allocations.

Comment:

One commenter (OAR-2002-0056-2267) requested that EPA provide in its model trading program rules for the use of a different time period to calculate baseline heat input for situations where to allocate additional allowances to the entities in recognition of their foresight and progressive investment in hydroelectric power (or other green power) such as Boiler #9. The commenter stated there is precedence under the Clean Air Act for substitution of baseline data when a baseline period is not representative of normal source operation. See 40 CFR 2.21(21)(ii) (NSR rules). The commenter noted that EPA has recognized that it should have discretion to allow the use of a different time period upon a determination that it is more representative of normal source operation. The commenter urged that EPA should exercise similar discretion in this case.

Response:

For existing units under the model trading rule, EPA is using the average of the highest three-year heat inputs achieved during the five-year period of 2000 to 2004 as the baseline for establishing plant mercury allocations. EPA proposed January 1, 2001, cut-off on-line date for considering units as existing units. The cut-off on-line date was selected so that any unit meeting the cut-off date would have at least five years of operating data, i.e., data for 2000 through 2004. EPA is concerned with ensuring that particular units are not disadvantaged in their allocations by having insufficient operating data on which to base the allocations. EPA believes that a

5-year window, starting from commencement of operation, gives units adequate time to collect sufficient data to provide a fair assessment of their operations.

States are required to achieve the mercury reduction requirements by reducing Hg emissions from coal-fired power plants. States are welcome to use set-asides (size determined by the State) for new units and any special policy objectives–such as promoting energy efficiency or renewables. The States, rather than this regulation can decide the best way to incorporate renewable incentives.

Comment:

One commenter (OAR-2002-0056-2918) understood that in the event that EGUs, burning a mixture of coal ranks, the MACT compliance limit will be adjusted based on pro-rata heat input calculation of each of the coal ranks in the mix of coal burned. Consistent with such an adjustment, the commenter recommended that EPA adopt a provision making each EGU responsible for obtaining periodic ASTM laboratory test data on coal burned by the EGU for each compliance period.

Similarly, if EPA adopts a cap and trade program, the commenter recommended that EGU owners be provided an opportunity to submit more recent coal rank data obtained by ASTM laboratory test methods for the coal burned during a time period that reflects more contemporary usage. The commenter stated that such coal rank data should be used by EPA in allocating Hg emission trading credits for the future year period(s) designated in the proposed cap and trade rule.

Whether EPA adopts Hg MACT emissions limits, or alternatively a Hg cap and trade program, the commenter stated that their recommendation will provide EGU owners the opportunity to adjust their Hg compliance requirements based on current coals burned. The commenter noted that coal fired EGUs do change coal suppliers and coal ranks over time because of changing market conditions and regulatory requirements. As such the commenter believed their proposal would add additional equity to EPA's Hg compliance requirements for EGUs.

Response:

As discussed in the final rule preamble, under its example allocation methodology, EPA has finalized for the model rule a "modified output" approach. This example method involves heat input-based allocations for existing coal units (with different ratios based on coal type), with updating to take into account new generation on a modified-output basis. It also utilizes a new source set-aside for new units that have not yet established baseline data to be used for updating.

For existing units under the model trading rule, EPA is using the average of the highest three-year heat inputs achieved during the five-year period of 2000 to 2004 as the baseline for establishing plant mercury allocations. EPA proposed January 1, 2001, cut-off on-line date for

considering units as existing units. The cut-off on-line date was selected so that any unit meeting the cut-off date would have at least five years of operating data, i.e., data for 2000 through 2004. EPA is concerned with ensuring that particular units are not disadvantaged in their allocations by having insufficient operating data on which to base the allocations. EPA believes that a 5-year window, starting from commencement of operation, gives units adequate time to collect sufficient data to provide a fair assessment of their operations.

The EPA believes that allocating to existing units based on a baseline of historic heat input data (rather than output data) is desirable, because accurate protocols currently exist for monitoring this data and reporting it to EPA, and several years of certified data are available for most of the affected sources. Under the EPA example method, existing units as a group will not update their heat input. This will eliminate the potential for a generation subsidy (and efficiency loss) as well as any potential incentive for less efficient existing units to generate more. This methodology will also be easier to implement because it will not require the updating of existing units' baseline data.

5.7.3 New Units

Comment:

One commenter (OAR-2002-0056-3437) did not support EPA's proposed alternative of using the lower of the NSPS for the different coal types or a rate based on the proposed 2018 cap rather than using a single emission rate for new units. The commenter stated that while this approach may address the differences between coal types and new and existing units, the commenter would still be concerned that using different information based on coal type could lead to fuel switching and the possibility of not achieving the desired reductions.

One commenter (OAR-2002-0056-3543) understood that new sources would be required to hold allowances equivalent to the product of their NSPS and baseline heat input. The commenter stated however, EPA is unclear what will be proposed as the baseline for new sources.

One commenter (OAR-2002-0056-3543) found the proposal unclear regarding how new sources would be treated under a cap and trade approach. The commenter noted new sources would be required to comply with the NSPS for mercury and be required to hold allowances. The commenter asked would new sources be given an allocation or is this up to the discretion of the states?

Response:

As discussed in the final rule preamble, under its example allocation methodology, EPA is finalizing the approach that new units will begin receiving allowances from the set-aside for the control period immediately following the control period in which the new unit commences commercial operation, based on the unit's emissions for the preceding control period. Thus, a source will be required to hold allowances during its start-up year, but will not receive an

allocation for that year. States will allocate allowances from the set-aside to all new units in any given year as a group. If there are more allowances requested than in the set-aside, allowances will be distributed on a pro-rata basis. Allowance allocations for a given new unit in following years will continue to be based on the prior year's emissions until the new unit establishes a baseline, is treated as an existing unit, and is allocated allowances through the State's updating process. This will enable new units to have a good sense of the amount of allowances they will likely receive - in proportion to their emissions for the previous year. This methodology will not provide allowances to a unit in its first year of operation; however it is a methodology that is straightforward, reasonable to implement, and predictable.

Although EPA is offering an example allocation method with accompanying regulatory language, EPA reiterates that it recognizes States' flexibility in choosing their Hg allocations method.

Comment:

Many commenters (OAR-2002-0056-2067, -2422, -2818, -2911, -2915, -2922, -3198, -3443, -3444, -3514, -3519) believed that the cap-and-trade program should have a set aside for new sources. Several of these commenters (OAR-2002-0056-2818, -2911, -2915, -3198) noted that a modest set aside would be consistent with the Acid Rain Program.

Several commenters (OAR-2002-0056-2818, -3198) submitted that this will ensure that new units operating in compliance with the NSPS will have legitimate access to allowances. One commenter (OAR-2002-0056-2915) stated that new unit development is critical to the continued use and development of Gulf Coast lignite for electric generation in Texas.

Commenter OAR-2002-0056-2911 suggested that once the size of the permanent allocation pool is determined, a small percentage of those allocations, 2 percent for example, can be set aside for new units each year. The commenter further suggested that any unused allocations would be returned to the pool for the other affected units. According to the commenter, similar concepts have been successfully incorporated into the trading program used for the NO_x SIP Call.

Several commenters (OAR-2002-0056-3443, -3519) submitted that the model rule proposal for a two percent new source set-aside was reasonable. One commenter (OAR-2002-0056-3443) believed this would be sufficient to prevent any inhibition to entry of new units in the market. The commenter asserted that redistribution of unused allowances from the set-aside to existing units is a critical piece of this proposal. The commenter believed the model rule should require that this redistribution be completed in time for existing sources to use them in the same budget year.

One commenter (OAR-2002-0056-3519) believed that new units should be defined as EGUs starting operation after the date of final rule adoption. One commenter (OAR-2002-0056-2922) stated that if EPA chooses a "cap-and-trade" program, it must ensure that new facilities have reasonable access to mercury emission allowances.

Similarly, one commenter (OAR-2002-0056-2067) stated that the proposed Cap and Trade alternative must give economic access to allocations to new power plants to allow for effective planning for construction of new units to meet growth and to replace retiring units. The commenter asserted that the Cap and Trade mechanism should not create obstacles to retiring older units or to adding new generation to ensure adequate security and reliability.

One commenter (OAR-2002-0056-3444) stated the cap and trade program should provide new unit set asides for new units operating prior to 2010.

One commenter (OAR-2002-0056-2725) stated that the West is one of the fastest growing regions in the country, and new coal plants are vital to affordable energy prices in the future and will be essential to continued growth in the economy. The commenter noted the DOE's Energy Information Administration projects a significant increase in construction of new coal–based power plants; the DOE/EIA Annual Energy Outlook 2004 with projections to 2025 forecasts the addition of 112 Gigawatts of new coal generating capacity. According to the commenter, if these new plants were to be prevented from being constructed because of new mercury regulations, the only alternative for this needed capacity would be natural gas. The commenter stated that due to physical and regulatory constraints, the supply of natural gas is not able to affordably meet its demand.

Over the next several years, the commenter expected several new, clean coal units to come on line in the West, and submitted that EPA should not burden these new units with overly stringent emission control requirements. Thus, the commenter supported adopting the allocation of mercury allowances for new units under the trading approach consistent with Senator Inhofe's approach to Clear Skies.

Many commenters (OAR-2002-0056-2042, -2375, -2422, -2519, -2862, -2907, -2815, -2922, -3440, -3478, -3556, -3565, -4191, -4891) stated there should be a modest mercury allowance set-aside for new units. Many of the commenters (OAR-2002-0056-2375, -2422, -2519, -2915, -3440, -3478, -3556, -3565, -4191, -4891) suggested the new unit set aside should be consistent with the 2 percent set aside for new facilities in Title IV Acid Rain Program. Several commenters (OAR-2002-0056-2915, -3440, -3478, -4191) believed new unit development would be critical to the continued use and development of lignite for electric generation in Texas. One commenter (OAR-2002-0056-3556)stated that any unused allocations would be returned to the pool for the other affected units. The commenter also stated that similar concepts have been successfully incorporated into the trading program used for the NO_x SIP Call. Similarly, a second commenter (OAR-2002-0056-2375) suggested the unused portion of the set aside should be returned to existing sources on a pro rata basis. One commenter (OAR-2002-0056-2907) stated that as we enter a new era where demand is beginning to exceed supply, new generation becomes essential. The commenter added, new coal generation is cleaner and more efficient than existing plants. The commenter believed that EPA should use an approach similar to that used in the Clear Skies Act to allocate mercury allowances to new units under a mercury cap and trade program. One commenter (OAR-2002-0056-3565) believed that new units should also be able to acquire mercury allowances from the allowance market.

One commenter (OAR-2002-0056-2422) noted that under a cap-and-trade approach, EPA has proposed NSPS emission limits equivalent to the NSPS proposed under the 112(d) regulations. The commenter believed the limit was set at a level that could not be achieved by the best performing units, and should be adjusted upward. The commenter was concerned that a cap-and-trade program would add another significant burden to new units if they are not allocated emission allowances. New units would be left to pursue allowances on the open market, with no guarantee of access. The commenter stated that EPA should reconsider how it will ensure that new units operating in compliance with the NSPS will have legitimate access to allowances. The commenter suggested that this could be achieved, for example, by requiring a modest set-aside of allowances from existing units, similar to the approach taken in the Title IV acid rain program.

One commenter (OAR-2002-0056-4891) stated that as proposed, the mercury rule would discourage the development of new power plants given that it would require new sources to procure allowances from the same pool of allowances applicable to existing sources. The commenter submitted that jeopardizing the ability to develop new power plants would ultimately put an untenable strain on the ability to meet the ever-increasing demand for affordable electricity in Texas and throughout the U.S. The commenter believed that to avoid this clearly undesirable result and ensure the continued development of new plants, new power plants should either be exempted from the requirement to obtain allowances, or be provided an allowance set-aside specifically for new units comparable to the 2 percent set-aside for new facilities in the Title IV, Acid Rain Program.

One commenter (OAR-2002-0056-4891) submitted that only existing facilities subject to the mercury rule should receive allowances. The commenter noted that as proposed, the mercury rule would discourage the development of new power plants given that it would require new sources to procure allowances. Jeopardizing the ability to develop new power plants would ultimately put an untenable strain on the ability to meet the ever-increasing demand for affordable electricity in Texas and throughout the U.S. To avoid this clearly undesirable result and ensure the continued development of new plants, the commenter stated new power plants should be exempted from the requirement to obtain allowances.

One commenter (OAR-2002-0056-2243) was concerned with how allowance programs are being developed. According to the commenter, when new projects were primarily gas-fired, the availability of an adequate allowance pool for new sources was not as important as it is today. The commenter pointed out that as coal-fired projects are conceived, the availability of access into the allowance market is critical. The commenter added that encouraging new project development is vital from both an economic and environmental point of view.

Response:

As discussed in the final rule preamble, the example allocation methodology includes a new source set-aside equal to 5 percent of the State's emission budget for the years 2010 to 2014 and 3 percent of the State's emission budget for the subsequent years. This is a change from the SNPR were EPA proposed a level 2 percent set aside for all years.

One commenter pointed to EIA forecasts for coal to grow by 112 gigawatts (GW) by 2025 and EPA economic modeling projects growth in coal by 2020. In order to estimate the need for allocations for new units, EPA considered projected growth in coal generation and the resulting Hg emissions portion of the Hg national cap. EPA believes the final new source set-aside provides for that growth.

Because States have flexibility in choosing their Hg allocations method, individual States using a version of the example method may want to adjust this initial five year set-aside amount to a number higher or lower than 5 percent to the extent that they expect to have more or less new generation going on-line during the 2001 to 2013 period. They may also want to adjust the subsequent set-aside amount to a number higher or lower than 2 percent to the extent that they expect more or less new generation going on-line after 2004. States may also want to set this percentage a little higher than the expected need, because, in the event that the amount of the set-aside exceeds the need for new unit allowances, the State may want to provide that any unused set-aside allowances will be redistributed to existing units in proportion to their existing allocations.

Comment:

One commenter (OAR-2002-0056-2830) believed the heat rate conversion factor of 8,000 Btu/kWh was too low for Fort Union lignite fired EGUs. The commenter stated that heat rates for units utilizing Fort Union lignite have improved over time. According to the commenter, the recent historical heat rate for existing Fort Union lignite-fired boilers is just under 11,000 Btu/gross kWhr. The commenter recommended that a heat rate conversion factor of 9,700 Btu/gross MWhr be employed for new lignite-fired units (69 FR 12409).

One commenter (OAR-2002-0056-2841) stated that the rule should not discourage new coal units. The commenter noted that new units undergoing permitting and/or under construction would not have the ability to establish a baseline heat input until going into commercial operation. The commenter also noted EPA has proposed an alternative to address the issue of no baseline by suggesting that the updated allocation for such units be adjusted by calculating the heat input for such units by multiplying the unit's output by a heat rate conversion factor of 8000 btu/kWh. EPA suggested that the 8000 btu/kWh rate represents a midpoint between expected heat rates for new pulverized coal plants and new integrated gasification combined cycle (IGCC) coal plants. The stated purpose for such an approach is to create level benefits for new units based on their output and encouraging efficiency. In principle, the commenter agreed with the approach selected by EPA to address units that will not have an established baseline. However, the commenter believed the selected conversion rate of 8000 btu/kWh rate cannot be supported and would unduly penalize new units.

The commenter stated the range of heat rates for IGCC units can be anywhere from 8400 btu/kWh to 9500 btu/kWh. Accordingly, the commenter did not believe the midpoint between IGCC and supercritical was appropriately established at 8000 btu/kWh. Given the current state of IGCC technology and the range of heat rates, the commenter did not believe that EPA should try to establish any presumed incentive for IGCC. Instead, EPA should only utilize

a rate that provides incentive to proven technology such as construction of a supercritical pulverized coal boiler that can be supported by Public Utility Commissions. The commenter recommended a conversion factor of 8900 btu/kWh that would provide the incentive to build supercritical units, while not penalizing companies through the utilization of an unrealistic and unsupportable conversion factor. Similarly, the commenter believed the conversion factor should not have the unintended consequence of encouraging the further utilization of natural gas for the production of electricity.

Similarly, one commenter submitted that the model rule's use of an 8000 Btu/kWh assumed heat rate for calculating allowance allocations appeared to be a mistake. The cmmenter noted that the model rule states that 8000 Btu/kWh represents the "mid-point" between the heat rate expected of new conventional coal and IGCC units. However, in the supplemental CAIR the same 8000 Btu/kWh is used as the "mid-point between gas fired combined cycle units and conventional coal units. The commenter agreed the 8000 Btu/kWh mid-point is reasonable for CAIR. However, the commenter pointed out that existing IGCC units have heat rates in the mid 8000s and conventional coal units have heat rates in the mid to lower 9000s. Consequently, the commenter believed 9000 Btu/kWh is the more appropriate mid-point for the mercury model rule.

The commenter also had concerns about using the midpoint approach at all since it would clearly favor IGCC technology over conventional coal technology. The commenter encouraged EPA to consider a separate heat rate for IGCC and conventional coal units. The commenter pointed out that the DOE clean coal roadmap goals for 2010 indicate that 9000 Btu/kWh for conventional coal and 8000 Btu/kWh for IGCC would be reasonable heat rates.

The commenter (OAR-2002-0056-2721) submitted that the new unit mercury allocation utilizing the modified heat output basis again places low rank fuels at a distinct disadvantage. The commenter noted that the modified heat output based procedure would take the three highest of the first five years of gross output and multiply it by a conversion factor of 8,000 btu/kWH. The commenter stated that this would place a plant efficiency incentive on new units so that the low rank coals would be unfairly punished. The commenter noted that EPA is requesting comment on the appropriateness of 8,000 btu/kWH. The commenter strongly encouraged EPA to establish a subcategory for heat rate conversion factor for low rank coals nearer 9,700 btu/kWH.

One commenter (OAR-2002-0056-2834) believed the proposed heat rate conversion factor of 8,000 Btu/kWh is to low for Fort Union lignite-fired EGUs. The commenter stated that heat rates for units utilizing Fort Union lignite have improved over time. According to the commenter the recent historical heat rate for existing Fort Union lignite-fired boilers is just under 11,000 Btu/gross kWh.

Response:

As discussed in the final rule preamble, under the example allocation methodology, allowances will be allocated to new units with an appropriate baseline on a "modified output"

basis. The new unit's modified output will be calculated by multiplying its gross output by a heat rate conversion factor of 8,000 Btu per kilowatt-hour (Btu/kWh). The 8,000 Btu/kWh value for the conversion factor is an average of heat-rates for new pulverized coal plants and new IGCC coal plants (based upon assumptions in EPA's economic modeling analysis). See documentation for the Integrated Planning Model (IPM) at http://www.epa.gov/airmarkets/epa-ipm). A single conversion rate will create consistent and level incentives for efficient generation, rather than favoring new units with higher heat rates.

EPA maintains that providing each new source an equal amount of allowances per MWh of output is an equitable approach. Because electricity output is the ultimate product being produced by electric generating unit, a single conversion factor based on output ensures that all sources will be treated equally. Higher conversion factors for less efficient technologies will effectively provide greater amounts of allowances (and thus a greater subsidy) to such less efficient units for each MWh they generate. This will serve to provide greater relative incentives to build new less efficient technologies rather than efficient technology. It should also be noted that, since all allocations are proportionally reduced after a new source is integrated into the market, higher conversion factors also lower allocations to existing sources.

Comment:

One commenter (OAR-2002-0056-3437) submitted that if EPA decides to include a new source set aside, states should be in charge of managing it and should be able to use some of it to encourage energy efficiency. The commenter felt it would be more equitable to use a methodology that allows all new units to receive some allowances to reduce the amount that may need to be purchased. The commenter believed this is especially important if sources are allowed to request up to 5 years of allowances. The commenter suggested that one option would be to increase the discount factor (0.90) to 0.80 or 0.75 or more. The commenter noted it is difficult to estimate the actual number of new units and the amount of allowances needed, but this is somewhat resolved by redistributing unallocated allowances back to existing units.

Regarding the allocation methodology, one commenter (OAR-2002-0056-3437) noted that EPA did not provide any basis for a discount factor of 0.90 to arrive at a final allocation.

One commenter (OAR-2002-0056-3437) commented on EPA's proposed alternative where new units would simply apply at the end of the year for allowances based on actual emissions. The commenter submitted that this is not a good alternative because sources would be uncertain about the actual amount of emissions and available allowances. The commenter believed that this could lead to a flurry of activity to try and buy allowances in a short time or risk noncompliance.

Response:

The example allocation methodology for the final rule does include these discount factors. As discussed in the final rule preamble, under its example allocation methodology, EPA is finalizing the approach that new units will begin receiving allowances from the set-aside for

the control period immediately following the control period in which the new unit commences commercial operation, based on the unit's emissions for the preceding control period. Thus, a source will be required to hold allowances during its start-up year, but will not receive an allocation for that year. States will allocate allowances from the set-aside to all new units in any given year as a group. If there are more allowances requested than in the set-aside, allowances will be distributed on a pro-rata basis. Allowance allocations for a given new unit in following years will continue to be based on the prior year's emissions until the new unit establishes a baseline, is treated as an existing unit, and is allocated allowances through the State's updating process. This will enable new units to have a good sense of the amount of allowances they will likely receive–in proportion to their emissions for the previous year. This methodology will not provide allowances to a unit in its first year of operation; however, it is a methodology that is straightforward, reasonable to implement, and predictable.

Although EPA is offering an example allocation method with accompanying regulatory language, EPA reiterates that it recognizes States' flexibility in choosing their Hg allocations method.

Comment:

One commenter (OAR-2002-0056-2181) stated that the proposal provides credit for the thermal output of new CHP facilities. The commenter believed this is a very important and beneficial provision that will help encourage the application of CHP. The commenter believed, however, the same credit should apply to existing CHP facilities. The commenter stated that the program should provide the maximum encouragement to CHP as a means of reducing energy consumption and emissions from the power and steam generation sectors. The commenter submitted that continued and increasing use of CHP can help reduce the cost of the program as well as producing significant coincident benefits for regulated and non-regulated pollutant reductions.

Response:

As discussed in the final rule preamble, under the example allocation methodology, existing units as a group will not update their heat input. This will eliminate the potential for a generation subsidy (and efficiency loss) as well as any potential incentive for less efficient existing units to generate more. This methodology will also be easier to implement because it will not require the updating of existing units' baseline data. Retired units will continue to receive allowances indefinitely, thereby creating an incentive to retire less efficient units instead of continuing to operate them in order to maintain the allowance allocations.

Comment:

One commenter (OAR-2002-0056-2913) stated that their newest, cleanest and most efficient electric utility steam generating unit was currently under construction, which because the unit commenced construction prior to January 30, 2004, it was classified as an existing unit as provided for in rule §63.9982(b). The commenter submitted however, if a cap-and-trade

program were promulgated as proposed this unit's mercury allowances would be allocated according to new unit criteria (i.e. a design output basis in lb/GWh) and only after it operated for five years.

According to the commenter, its newest unit would be allocated mercury allowances based on the unit's heat input which, for the first five years of operation, would be converted to gross electrical output using a predetermined conversion factor of 8,000 Btu/kWh. The commenter stated that 8,000 Btu/kWh is not applicable under any cogenerating circumstances and is extremely aggressive under best case conditions and leaves no allowance for equipment degradation due to low load conditions, equipment degradation or non-optimal process operations. The commenter further stated that any heat input used for co-generation purposes would only be converted at one-half of the actual rate and that mercury allowances would then be allocated based on these artificially low heat input conversion rates; these allowances would be reduced further by an additional 10 percent before being allocated for use. Beyond the penalties already imposed on this unit (i.e. no allowance for mercury content in the limestone used for SO_2 control purposes as discussed above) the commenter claimed they will be further penalized by this allocation process and questions the appropriateness of applying what is in essence a new source limit/allocation process to an existing unit.

While the commenter believed the set-aside allocation process as currently proposed was flawed, they expressed a much larger concern. According to the commenter, under the allocation process proposed in §60.4142(c)(4)(iii) and (iv), there was a distinct possibility that they would not be allocated enough mercury allowances to operate its newest unit regardless of the amount of the proposed set-aside, due to the fact that a large new electric utility steam generating unit could potentially require and be granted the entire amount of allowances set-aside. The commenter stated that they would then be faced with the possibility of not being able to achieve "… the maximum degree of reductions …" on its own even though it would use the very technology EPA relied upon in setting the EGU MACT standard in the first place. The commenter did not believe this is what Congress envisioned when it passed CAA section 112 into law. While the list of compliance measures, processes, methods, systems or techniques delineated in CAA section 112(d)(2)(A)-(E) is, admittedly, not all inclusive, the commenter argued they would essentially be prevented from using any of them to achieve compliance with the MACT standard under a cap-and-trade program not "funded" with sufficient set-aside allowances.

As a remedy, the commenter offered that one way to treat all existing units equitably would be to allocate mercury allowances to all existing units whether or not they operated during the initial baseline period and whether or not they operated for five years or more. The commenter stated that one could look to §60.4142(c)(3) for guidance on what EPA believed was appropriate for initial mercury allowance allocations for units that have not operated for five years or more. To implement the stated policy consistent with the approach outlined in §60.4142(c)(3), the commenter offered suggested modifications to §60.4142.

Response:

The example allocation methodology for the final rule addresses the commenter's concerns about new units. As discussed in responses above, the example allocation methodology includes: a new sources set-aside, allowance allocations for a given new unit based on the prior year's emissions until the new unit establishes a baseline, and no inclusion of discount factors.

Comment:

The commenter (OAR-2002-0056-4891) added that with the exemption option, new power plants should be exempted from the requirement to purchase allowances as long as they have NSPS Subpart Da technology operational when they initiate operations, and they adhere to monitoring and reporting requirements to demonstrate continuous compliance. By the same token, facilities that are not subject to the UMRR should not be able to receive credits and thereby receive windfall gains on the allowance trading markets.

Response:

In the final CAMR, new sources will be covered under the Hg cap of the trading program, and will be required to hold allowances equal to their emissions. EPA maintains that is essential to include new sources under the cap to ensure that environmental goal of reducing mercury emission is achieved. With new sources under the cap, the environmental goal continues to be achieved despite future growth in the electric power sector, as older coal-fired generation is retired and replaced new coal-fired generation

Comment:

Several commenters (OAR-2002-0056-2834, -2898) submitted that Springerville Units 3 and 4 should receive allocations in the same manner as other "existing units." The commenters stated that the Springerville Generating Station was recently permitted for the addition of two new 400 MW net coal-fired units. The permit for the addition of Springerville Units 3 and 4 was received on April 29, 2002, and construction of the phased project began on October 22, 2003, with Unit 3 scheduled for completion in 2006 and Unit 4 at a later date. Two other Units already exist at the site, Springerville Units 1 and 2.

The commenters stated that units such as Springerville 3 and 4 should receive allocations in the same manner as other "existing units" since construction commenced on or before January 30, 2004. The Springerville units 3 and 4 are "existing units" for the purpose of determining the applicability of the proposed rule. The commenters noted that under either section 111 or 112, an "existing unit" is one for which construction, modification, or reconstruction commenced on or before January 30, 2004 (69 FR 4662 and 69 FR 4690). The commenters stated that Units 3 and 4, however, are not listed as part of those existing units receiving mercury allowances under a Cap and Trade program. Under the proposed rule (69 FR 12446), units that "commence operation on or after January 1, 2000" receive allocations according to a different approach, regardless of whether they are "new" or "existing units." The commenters felt that, since

construction of Springerville Units 3 and 4 commenced on or before January 30, 2004, these units should receive allocations in the same manner as other "existing units." Commenter 2898 added that due to the fact that there is no historical heat input for these units, the "baseline heat input" (prior to multiplying by the adjustment factors) should be calculated using the maximum potential heat input for the units and a capacity factor of 90 percent. The commenter noted that units of this nature are invariably intended to provide base load power, and the allocation methodology must recognize this fact.

Response:

Under the example allocation methodology, a new unit is defined as a unit commencing operation after January 1, 2001. For purposes of allocating emissions, EPA believes that existing units need five years of heat input data to establishes it baseline heat input. This is consistent with the overall allocation approach, under which new unit establishes a baseline after 5 years of operation, is treated as an existing unit, and is allocated allowances through the State's updating process.

5.7.4 Auctions

Comment:

Many commenters (OAR-2002-0056-1834, -1969, -2117, -2161, -2180, -2267, -2375, -2721, -2830, -2835, -2850, -2867, -2891, -2898, -2911, -2922, -2948, -3443, -3445, -3543, -3546 -3556, -3565) opposed the auctioning of mercury allowances. One commenter (OAR-2002-0056-3565) believed states do not have that authority and allowances should be allocated free. A second commenter (OAR-2002-0056-2891) stated that EPA had no regulatory "taxing" authority under section 112 or section 111 to mandate the auctioning of mercury allowances, and the auctioning of allowances would be poor public policy because it would increase the cost of an already expensive proposal. The commenter further stated that a mercury cap-and-trade program could be constructed in many ways to help ensure an equitable and cost-effective program. The commenter noted that EPA requested comment on whether it could and should impose an auction program under either a section 112(n) or section 111(d) Federal Implementation Program cap-and-trade program, at 12408. The commenter stated that in short, it is neither legal nor appropriate for EPA to implement any auction program of mercury allowances.

Commenter OAR-2002-0056-2891 stated that first, EPA had no legal authority under the CAA to auction or require the auctioning of mercury allowances under either proposed cap-and-trade programs and conspicuously cited no legal authority in the proposal. According to the commenter, the only auctioning of allowances the EPA has authority to conduct is specifically delineated by an act of Congress in the 1990 CAA Amendments, section 416, under "acid rain" control. The commenter stated that even under section 416, the auction proceeds are redistributed to the original allowance holders. The commenter further stated that auction proceeds would be effectively a tax on those required to purchase mercury allowances. The commenter believed that EPA's contention, at 12408 col. 2, that it might have regulatory

authority to collect taxes and deposit the proceeds in "general revenues" under the Miscellaneous Receipts Act was unfounded.

The commenter added that the policy goals EPA claimed an auction would achieve can be accomplished by less draconian and more legal means. The commenter stated that for example, a "new source set aside" provision alternatively suggested by EPA, at 12408-12409, could be constructed to accomplish the same objectives without unnecessarily driving up the costs of what will be an already expensive program.

One commenter (OAR-2002-0056-2922) opposed auctions or any other method of forced sale of allowances.

Several commenters (OAR-2002-0056-2161, -2948) opposed auctions, but stated that if EPA decided to permit auctions, auctions should not be for the initial allocations of allowances, but only for a very small percentage of allowances each year as in the Title IV program. One commenter (OAR-2002-0056-2161) noted that the infrastructure for an allowance program is already in place as a result of the Acid Rain Amendments, and it should be relatively simple to add mercury allowances to the program already in existence.

Several commenters (OAR-2002-0056-2180, -2267, -2835, -2898, -3445) supported an allocation system and opposed an auction. One commenter (OAR-2002-0056-2898) recommended that mercury allowances be allocated to sources by EPA. Several commenters (OAR-2002-0056-2267, -2835, -3443, -3445) stated that mercury emissions would be controlled at substantial cost, and to pay for allowances in addition to the mercury controls would add substantial cost with no added environmental benefit. One of these commenters (OAR-2002-0056-3445) did not believe that additional reductions would occur from sources seeking to reduce the cost of allowances; it was not anticipated that additional reductions will be possible, based on the available and developing control technologies.

Commenter OAR-2002-0056-2267 submitted that allocating allowances for free would provide assistance to the entities incurring most of the costs of complying with the necessary mercury reductions, lessening the financial impact of the program on these sources. One commenter (OAR-2002-0056-2180) submitted that affected units will pay twice, once to reduce emissions and second to pay for allowances they need to operate. Commenter OAR-2002-0056-2835 suggested that if any allowances are withheld from affected EGUs for auction, proceeds from auction sales should be remitted to the original holders from which the allowances were withheld. Commenter OAR-2002-0056-3443 submitted that auctioning allowances would increase the price of electricity due to the increased stringency of the emission standard resulting from the requirement to purchase allowances and invest in control equipment. The commenter stated that well-documented studies show clearly that affordable electricity is a key element in public health policy. The commenter felt that placing a tax on electricity could undermine the health-benefits sought to be gained by this rulemaking.

Several commenters (OAR-2002-0056-2991, -3556) believed that if states were allowed to sell allowances at auction (or otherwise) rather than allocate them without charge, it would

substantially change the cost analyses for the standard of performance that EPA has conducted. The commenters added that it would add to the variability of the implementation of the trading program, hindering the development of a robust program.

One commenter (OAR-2002-0056-3543) believed auctions would not be necessary under an open market free trade system. The commenter submitted that the use of a safety valve mechanism, or capping allowance prices, may dictate decisions to install controls instead of the market price for an allowance. This would be counter to the idea that decisions to control emissions are driven by the cost effectiveness of controls compared to purchase of allowances. The commenter believed the safety valve mechanism also may hamper EPA's ability to assess penalties for noncompliance.

One commenter (OAR-2002-0056-3546) stated that requiring controlled sources to both reduce emissions and pay for allowances to cover their remaining emissions would impose significant costs on emitting sources. These additional allowance costs would be unnecessarily burdensome and costly to fossil fuel-fired generation. In contrast, the commenter believed allocating allowances to regulated sources would lessen the financial impact of this very costly control program.

Several commenters (OAR-2002-0056-1969, -2830, -2850) disagreed with EPA's proposal to have an annual auction for mercury allocations under a cap-and-trade approach. According to the commenters, considering the uncertainty of the availability of mercury controls and monitors, the risk to the existing coal-fired electric generating units would be high. The commenters believed that, to alleviate some of the risk, the mercury caps should be fully and permanently allocated to the existing electric generating units as is done under the Title IV sulfur dioxide program. The commenters stated that new units would be better able to minimize risks since they would be able to design systems and select fuels to minimize mercury emissions, which is something that many existing units cannot do. The commenters asserted that if EPA decides to allocate allowances to new units, it should not be done at the expense of existing units. The commenters suggested that if EPA decides to implement an auction, EPA should manage that auction program at the national level rather than having it managed by the individual states.

One commenter (OAR-2002-0056-2721) noted that allowance auctions would be the responsibility of the individual state. The permanent allowance system would not take into account new units, unless there was a new unit set aside. The commenter would be concerned with the quantity of the set-aside as it is difficult to anticipate the rate of new units coming on-line. An additional concern would be that the set aside would not be available for existing sources.

One commenter (OAR-2002-0056-2861) opposed giving states the option of distributing allocations through an auction. The commenter submitted this is not a necessary element of an environmental control program. The commenter added that auctioning allowances would not produce any additional reduction in emissions. It would simply increase the cost of the regulatory program to companies and ultimately to consumers by requiring regulated entities to

pay for every ton emitted. The commenter stated that auctioning of mercury allowances would simply not be an economically efficient policy. The commenter added, as UARG has argued in its comments, a state does not have the authority to auction allowances because to do so would fundamentally change the cost analysis that EPA used to establish the mercury performance standard.

One commenter (OAR-2002-0056-3437) stated that, although EPA proposes it, the auction allowance work would fall to the states. While it may be beneficial to have a pool of revenue available, there could be resource issues with establishing and implementing an auction program. The commenter asserted that if EPA includes auctions, this must be voluntary and not a requirement.

Response:

For States participating in the EPA-administered CAMR cap-and-trade program, States have the flexibility to determine their own methods for allocating Hg allowances to their sources. Specifically, such States will have flexibility concerning the cost of the allowance distribution, the frequency of allocations, the basis for distributing the allowances, and the use and size of allowance set-asides.

As discussed in the final preamble, although there are some clear potential benefits to using auctions for allocating allowances, EPA believes the decision regarding utilizing auctions rightly belongs to the States and Tribes. EPA is not requiring, restricting, or barring State use of auctions for allocating allowances. An example of an approach where CAMR allowances could be distributed to sources through a combination of an auction and a free allocation is provided in the preamble.

5.8 OTHER TRADING MECHANISMS

5.8.1 Banking

Comment:

Several commenters (OAR-2002-0056-1673, -1859, -2375, -2547, -2718, -2862, -2867, -2883, -2900, -2922, -2948, -3509, -3565) stated there should be no restrictions on banking of emission allowances. Several commenters (OAR-2002-0056-2547, -2718) supported a provision for unrestricted banking as a way to encourage early emissions reductions, stimulate the trading market, encourage efficient pollution control, and provide flexibility to affected sources in meeting environmental objectives. One commenter (OAR-2002-0056-2900) noted that, like the Acid Rain Program, the Mercury Budget Trading Program proposed unlimited banking without the flow control provisions of the NO_x Budget Trading Program. The commenter supported unlimited banking of allowances allocated to sources under each phase of the Program and did not see any advantage to a flow control provision. Commenter OAR-2002-0056-2862 also believed there should not be any restrictions such as flow control. This commenter stated that because mercury is a chemical that bio-accumulates in the environment, and because the

behavior of mercury emissions are not exacerbated by seasonal weather conditions (such as the proclivity for ozone formation development during hot, humid summer months), any reduction in mercury in advance of a compliance date would result in a net environmental gain.

Response:

EPA has finalized that banking will be allowed without restriction after the start of the Hg cap-and-trade program in 2010.

Commenter (OAR-2002-0056-2375) submitted that a mercury cap-and-trade program should include provisions for early reduction credits (ERC) and banking of mercury credits. The commenter supported unrestricted banking of all ERCs and Phase I and II excess credits without discount, except the banking of Phase I credits should be restricted if EPA determines in 2009 that IAQR reduction co-benefits result in emissions less than 34 tpy and EPA sets the cap at 34 tpy. Sources would be permitted to use vintage Phase I credits during Phase I without discount and vintage Phase II credits during Phase II without discount.

Response:

EPA has finalized that banking will be allowed without restriction after the start of the Hg cap-and-trade program in 2010. Given that the 2010 cap is set at a level that represents Hg co-benefit reductions under CAIR, EPA did not propose, and is not finalizing, an early reduction credit provision, because the cap-level does not require the installation of Hg specific controls. Under CAIR, Acid Rain Program sources will be able to bank SO_2 allowances from additional reductions before 2010 that may also result in ancillary Hg emission reductions.

One commenter (OAR-2002-0056-3443) recommended in view of the environmental benefits fostered by a program that allows allowances to be banked in advance of the deadline for a cap, that early reduction credits should be allowed for calendar years 2008 and 2009. The commenter has long held that early reduction programs be made part of all cap and trade programs. The commenter believed that early reduction programs work to promote clean air sooner by encouraging the early installation of new technologies. The commenter installed state-of-the-art scrubbers in advance of the statutory deadlines under the successful Title IV program. Likewise, the commenter installed the nation's first SCRs burning high sulfur coal in advance of the NO_x SIP Call. For a mercury cap and trade program, the commenter asserted that the utility industry needs banking of early reduction credits because of the uncertainty in its ability to control mercury emissions over the long term. The commenter noted that as the preamble acknowledges, a banked allowance is one less ounce of mercury emitted in a given year. Thus, an early emissions banking program has the advantage of achieving reductions in advance of the 2010 compliance date for a Phase I cap.

The commenter recommended an early emission banking program would be based on the mass of reductions produced from the installation of an emissions control device on an individual unit basis, as was done in the NO_x SIP Call. In addition to providing environmental improvements, the commenter believed this program also provides an opportunity to address

important monitoring issues since utilities choosing to participate in the program would have to start monitoring for mercury in 2008 for units in this early reduction program. The commenter stated credit would be earned on an individual unit basis at levels below their Phase I allocation. The commenter estimated that on a yearly basis, they might earn three to six percent of their Phase I allocation level. The commenter noted this is a small amount, given that the current best mercury emission monitoring method (the Ontario Hydro Method) has a 10 percent accuracy level.

Given the limited experience industry has had with mercury CEMs or equivalent methods, the commenter believed several monitoring issues would have to be resolved prior to the onset of monitoring. For example, substitution of missing data is just one of the many issues that the commenter felt need to be addressed. The commenter submitted an early banking program, starting in 2008, would allow EPA to address these issues prior to the imposition of the first cap in 2010.

The commenter submitted that excessive bank accumulations could be minimized by discounting the banked allowances in 2018 by a certain pre-set percentage. The commenter believed the interim cap and the discounting of allowances would ensure that actual emissions in 2018 are close to the Phase II cap of 15 tons per year. The commenter stated that this approach provides the flexibility of building some allowances prior to program initiation in 2010 to hedge against the uncertainty in the estimate of achievable mercury reductions. This approach would also be environmentally preferable because it would encourage earlier reductions and then in 2018 permanently retire allowances.

Response:

Given that the 2010 cap is set at a level that represents Hg co-benefit reductions under CAIR, EPA did not propose, and is not finalizing, an early reduction credit provision, because the 2010 cap-level for CAMR does not require the installation of Hg specific controls. Under CAIR, Acid Rain Program sources will be able to bank SO_2 allowances from additional reductions before 2010 that may also result in ancillary Hg emission reductions. EPA has finalized that banking will be allowed without restriction after the start of the Hg cap-and-trade program in 2010. The ability of affected sources to bank Hg allowances starting in 2010 will promote earlier reductions than would otherwise be achieved in the program, and help to stimulate the Hg allowance market.

Comment:

One commenter OAR-2002-0056-3445 stated that they are already installing equipment to make significant reductions in NO_x and SO_2 emissions. The commenter added that they and their customers have made a substantial investment in the NO_x and SO_2 control technologies, one that the commenter believed will have a substantial level of mercury reduction co-benefits. The commenter added that this equipment will be operational as much as five years before EPA's proposed initial compliance deadline, resulting in less overall mercury emissions to the environment.

The commenter believed that banking should be allowed, so the credits that the commenter earns by acting early may be used to offset later emissions or as a reserve in the event of equipment failure. A significant amount of the commenter's generation comes from nuclear power, which emits no mercury. The commenter pointed out that if any of those nuclear units experienced an unexpected outage, generation must be made up from the fossil plants, which could result in unanticipated mercury emissions. With limits as tight as the proposed 15-ton cap in 2018, the commenter believed that banked emissions credits should be available to offset the unexpected mercury emissions from such an event.

The commenter stated that banking would encourage companies to install and operate pollution control equipment early, at significant operating cost, so that the banked allowances could be used when additional equipment could not be installed in the limited time available. The commenter added that banking also encourages companies to operate pollution control equipment to achieve maximum emissions reductions, accumulating a pool of allowances that can be used as a reserve in case of the unforeseen loss of a non-emitting or controlled unit, during periods of necessary but unexpected maintenance, and in the event that some controls do not perform as designed.

The commenter stated that utilities like them that have a significant number of non-mercury emitting generation units (e.g., nuclear and gas) must plan for fluctuations in their operations, based on long-term maintenance and refueling cycles. The commenter added that these plans impact the plants' year-to-year operations and the commenter's overall emissions. The commenter further added that weather is also a factor in plant operations. According to the commenter, an extremely hot summer or cold winter could result in a significant emissions increase relative to the original plan, which would be based on "normal weather assumptions" for that period. The commenter stated that banking would provide a cost-effective mechanism for dealing with the expected year-to-year emissions fluctuations while ensuring long-term compliance.

Response:

EPA has finalized that banking will be allowed without restriction after the start of the Hg cap-and-trade program in 2010.

Several commenters (OAR-2002-0056-1596, -2071, -2064, -2094, -2359, -3398, -4139) stated that banking should not be allowed or should be restricted. One commenter (OAR-2002-0056-2359) opposed EPA's proposal to allow units to bank early emission credits with no restrictions to be used in meeting reductions under CAA section 111. If banking and trading were allowed, the proposed 15-ton final cap in 2018 would increase to 22 tons or only a 54 percent reduction. The commenter believed that the banking of emission credits should be restricted and that at a minimum, credits should expire by a final compliance date. Commenter OAR-2002-0056-3398 rejected banking prior to the 2018 compliance date because it would extend the timeframe for meaningful reductions and may further contribute to hot spots. One commenter (OAR-2002-0056-4139) did not support banking of allowances without restrictions. The commenter believed the availability of banked allowances should be decreased either

through time-generated reductions (i.e., allowances expire after a definite time period) or by requiring the use of older banked allowances on an increasing ratio based on age (i.e., 1 to 1.5 or 1 to 2). One commenter (OAR-2002-0056-1596) stated that any banking of allowances must include an extra reduction for each transaction for environmental improvement. For example, when 100 units are retired, an additional 5 units should be retired.

Response:

Banking would achieve greater cumulative reductions early in the program than would be required by the final cap, and will not increase cumulative emissions over the entire length of the program. Banking has several additional advantages, including the potential to encourage earlier or greater reductions from sources, stimulate the market and encourage efficiency, and provide flexibility in achieving emissions reduction goals (e.g., by allowing for periodic increased generation activity that may occur in response to interruptions of power supply from non-Hg emitting sources).

5.8.2 Safety Valve Provision

Comment:

Many State Attorney Generals (OAR-2002-0056-2823) stated there is no legal or policy basis for establishing a "safety valve," which would set a maximum cost for mercury emission allowances. The commenters asserted EPA lacks both authority and a policy basis for adopting a safety valve. The commenters believed the safety valve would provide incentive to deter emission reductions and should be withdrawn. The commenters noted that even if authority existed, EPA presented no legal or technical basis for the proposed price of $2,187.50. The commenters stated the provision is also unnecessary for a market-based program and would undermine its purpose–to use market incentives to achieve timely reductions.

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble.

Comment:

Similarly, several states (OAR-2002-0056-3437, -3449, -4139) did not support the safety valve provision. One commenter (OAR-2002-0056-3437) stated safety valves have not been needed in the Acid Rain or NO_x programs, and they would require EPA to speculate about too many uncertainties, such as the allowance price. One commenter (OAR-2002-0056-3449) submitted the safety valve provision to avoid controls if the cost is greater than $35,000/lb is inappropriate and arbitrary. The commenter noted the dollar value was not linked to the environmental cost which result from excess mercury emissions. The commenter believed that it appeared to be linked to EPA's arbitrary notion of what level of cap is supported by the proposed

rule. The commenter also believed costs of control over $100,000/lb were justified based on the economic loss of fish, sports fishing industry, and the lifetime economic loss of brain damaged people due to in utero exposure.

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble.

One commenter (OAR-2002-0056-4139) submitted that allowing sources to purchase allowances under a safety valve price guarantee may discourage companies from seeking more cost effective means to control mercury. The commenter pointed out this could inhibit advancement of new technologies because sources would control only to a set dollar amount regardless of advances in control technology.

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble.

Comment:

Public interest group comprehensive comments (OAR-2002-0056-3459) stated that the safety valve provision should be discarded because it would permit pollution levels to remain artificially high and because EPA expects it to be used to avoid pollution controls. Even though purchased safety valve allowances would be deducted from the next year's allocation, there does not seem to be any limit on using the provision to borrow again year after year and avoiding controls indefinitely. The commenters noted that EPA's own IPM modeling showed it is bad environmental policy that would increase emissions in the years 2023-2030 beyond the cap of 15 tpy (to 22 tpy). It also would have the potential to delay controls if the price were cheaper than controls. The commenters observed that EPA did not even address the possibility of local problems resulting from the safety valve provision. It also would create a huge paradox associated with the continual borrowing of future allowances without ever reconciling the borrowed allowances from future compliance periods. As written, the commenters submitted the proposed provision would allow a plant to comply by purchasing allowances into the future.

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble.

Comment:

One commenter (OAR-2002-0056-2897) expressed concern about the proposed safety valve mechanism and suggested that this concept be revisited, as it seemed to undermine the market value concept of Title IV. The commenter noted that the concept suggests that there would be unlimited allowances available at a fixed and arbitrary price unrelated to market conditions and that these allowances could be borrowed against ad finitum into the future. The commenter questioned whether this truly incentivizes commercialization of technology.

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble.

Comment:

The commenter (OAR-2002-0056-2897) stated that borrowing of future allowances may be acceptable if there will be only minor noncompliance issues in the years immediately following initial implementation. The commenter asserted that, however, this could not be guaranteed and continued borrowing of out year allowances would be extremely problematic. The commenter stated that an alternative approach may be to allow utilities to purchase off-system reductions from outside the electricity-generating sector, if their control costs exceed the safety valve value. According to the commenter, this would eliminate the risk that utilities face from excessive control costs while continuing to reduce the mercury emitted to the environment. The commenter believed over time, the depletion of these off-system reductions would help incentivize mercury control technology.

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble.

Comment:

Several commenters (OAR-2002-0056-2180, -2375, -2519, -2547, -2718, -2721, -2830, -2835, -2850, -2861, -2922, -2948, -3509, -3522, -3565, -4891) supported the establishing of a safety valve. Several commenters (OAR-2002-0056-2375, -2718, -2903, -3522) supported an enhanced, appropriately designed safety valve provision because it could solve critical problems of implementing the trading program while ensuring compliance with and the integrity of the Phase I and II caps. Specifically, the commenters supported a Phase I safety valve set at $15,000/lb. and a Phase II safety valve set at $35,000/lb. However, the commenters objected to EPA's proposal to deposit safety valve funds into the general treasury and to deduct safety valve allowances from future years. The commenters proposed that safety valve funds should go into a

Mercury Reduction Fund (MRF) and be used to fund the development of innovative technologies and/or purchase additional off-utility system mercury reductions. The commenters proposed that because the MRF could yield net mercury reduction benefits, there would be no need to confiscate safety valve credits from future years.

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble. Further, it should be noted that under section 111 where state plans have been approved, funds from the sale of safety valve allowances would have been collected by the States, not EPA.

Comment:

One commenter (OAR-2002-0056-4891) stated the safety valve provision is intended to and would, in fact, minimize some of the uncertainty and unanticipated market volatility that may be associated with the cost of mercury rule compliance. The price of allowances would be capped such that, if the allowance price exceeds the "safety-valve" amount, sources would be authorized to borrow allowances from following years to have access to more allowances available at that price. The commenter submitted that perhaps the primary benefit of this provision is that it would render the cost of complying with the mercury rule requirements somewhat predictable and limited, though extremely costly.

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble.

Comment:

One commenter (OAR-2002-0056-2835) emphasized that the success of a safety valve mechanism would depend on the design of the state allocation system–i.e., the availability of undistributed allowances from which the sources could borrow–and highlighted the need for consistent allocation methods across the various state programs.

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble.

Comment:

One commenter (OAR-2002-0056-3431) noted that EPA has proposed a safety valve provision that sets the maximum cost purchasers must pay for mercury emission allowances. The commenter observed that EPA proposed a price of $2,187.50 for a mercury allowance (one ounce); this price would be adjusted annually for inflation. The commenter stated that safety valve allowances could be used to cover any shortfall between reported emissions and the allowances needed to cover those emissions. The commenter observed that as proposed, allowances purchased by a power plant through the safety valve mechanism would come out of the budget for future years from the state within which the power plant is located and, in EPA's example, would be taken out of the pool of allowances available for units that have been generating for at least five years. The commenter stated that this would result in reduced future allocations for all plants in that state. According to the commenter, it would be unwarranted and inequitable for other plants in the state to be penalized as a consequence of another plant taking advantage of the safety valve mechanism. The commenter stated that this potentially is an especially problematic issue for plants in states that have a small number of coal-fired power plants. To address this problem, the commenter suggested that the mechanism be revised to have the "borrowed" safety valve allowances come out of the overall nationwide budget, not individual state budgets. The commenter also suggested that alternatively, the mechanism could be changed to allow plants to use future year allowances for compliance in an earlier compliance year, at no charge, but on a discounted basis. According to the commenter, this would eliminate the problem of penalizing plants for the use of the safety valve mechanism by other plants in its state, while making sure there isn't excess "borrowing" of future years' allowances through the discount provision.

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble.

Comment:

One commenter (OAR-2002-0056-2634) believed that the EPA's safety valve provision is not a true safety valve in that it requires the confiscation of future years' allowances. The commenter stated that the purpose of the safety valve is to ensure reliability in the electrical system by providing units a means of compliance even if technology does not develop at the rate currently anticipated. The commenter believed confiscation of future years allowances would only exacerbate the problem. The commenter suggested that if EPA ultimately decides that the safety valve provision will include borrowing of future years allowances, allowances should be borrowed from the general pool and not against an individual units account. If the safety valve were triggered, it would not be the result of any business decisions made at a unit level, rather it would be a reflection of the state of technology across the industry. Therefore, the cost burden should also be spread across the industry.

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble.

Comment:

One commenter (OAR-2002-0056-1969) was unclear how a safety valve will be an effective tool to minimize unanticipated market volatility if the future year cap is reduced by the borrowed amount. The commenter stated that it certainly could alleviate compliance concerns at the point in time when the safety valve is triggered, but also noted that, on the other hand, triggering the safety valve in multiple years could compound future compliance requirements unless industry were able to effectively reduce future mercury emissions within a reasonable time frame.

Similarly, one commenter (OAR-2002-0056-2850) supported the safety valve if it does not involve replacement of credits from future allocations. The commenter believed an interim phase buyout price of $10,000 per pound mercury should be considered, shifting to EPA's proposed $35,000 per pound value at the final phase of the program (2018). The commenter stated that the price cap is critical considering that there is no commercially demonstrated control technology. The commenter suggested that the pay back component be eliminated, since that only serves to make future year compliance all the more difficult while emerging technology is commercialized.

One commenter (OAR-2002-0056-2861) suggested that some restriction is needed on the use of the safety valve to assure that borrowed allowances do not affect the future allocations of sources that met compliance without the need to borrow.

One commenter (OAR-2002-0056-2180) suggested that proceeds from the safety valve should be returned to other allowance holders or held in escrow until the user of the safety valve can return the borrowed allowances.

Several commenters (OAR-2002-0056-2948, -3565) requested EPA to modify their proposal to enable a unit to borrow from its own future-year allowance account (resulting in fewer allowances available to that unit in future years). Commenter OAR-2002-0056-2948 stated this would avoid a situation where units that did not borrow allowances are forced to bear part of the burden of a reduced number of available allowances in future years. Commenter OAR-2002-0056-3565 recommended that the unit borrowing from its own future-year allowance still pay EPA the $2,187.50 per allowance for the privilege to borrow against future years. The commenter believed the unit should not be borrowing from the general pool of allowances available to all units within the state as EPA has proposed. The commenter stated that this would result in fewer allowances available for allocation in future years, not just to the units that borrowed allowances, but to all units. The commenter noted that EPA also proposes that funds received from the purchase of safety valve allowances be deposited in the United States

Treasury. The commenter requested that these funds instead be provided to the United States Department of Energy to assist in the development of innovative mercury emissions control projects, such as Powerspan's Electro Catalytic Oxidation technology.

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble.

Comment:

One commenter (OAR-2002-0056-3443) stated that EPA has asked for comments on the need for a safety valve mechanism under which the price of allowances is effectively capped. See 69 FR 12397 and 12410. The commenter can support the inclusion of such a mechanism in the trading rule but contended that an early reduction credit program would be a more effective tool for dampening the market volatility that could result from implementation of a cap and trade program. The commenter believed an early reduction program would be a better policy and market tool since it would grant credit for reductions made early rather than grant credit for the promise of greater future reductions. The commenter noted early reduction allowance programs have been part of previous cap and trade programs, and are better suited to dampen market volatility by making emission credits available ahead of compliance deadlines. The commenter pointed out that the safety valve mechanism, by contrast, would attempt to artificially restrain the market price of allowances. The market price of an emission allowance obtained via a safety valve provision could vary greatly depending on the final source of that emission allowance, creating situations in which the safety valve would have little effect on dampening market volatility or facilitating compliance decisions.

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble. See the discussion of early reduction credits in following section.

Comment:

One commenter (OAR-2002-0056-1842) offered the following "variable mercury safety valve plan," based on the mercury cap and trade proposal.

Proposition: Variable mercury safety valve allowance pricing should be included in the proposed mercury and cap and trade rule.

Purpose: To eliminate the impasse over feasability. This impasse is largely based on the question of mercury technology performance. Variable pricing eliminates the need to address this question.

Proposition Specifics: Present proposals call for absolute diminishing caps with a fixed safety valve price approach. This should be changed to single cap target (5 to 10 tpy) with safety valve allowance prices which start low but increase yearly. The result is that the achievement of the target is probable but the maximum cost is predictable.

Background: Much of the debate centers on the amount of mercury removal which should be achieved in various years. The differences are not about the goal but about the cost of obtaining the goal. Power plants in the U.S. presently emit 48 tons (96,000 lb) of mercury/yr. Environmentalists contend that 90 percent of the mercury can be removed with known technology and are calling for a five ton mercury cap in 2007. Power plant owners believe there is no reliable technology available and are questioning whether a 26 ton cap in 2010 is too onerous. However, both agree that by 2018 it is necessary to remove between 70-90 percent of the mercury.

Mercury is bio-accumulative. Therefore mercury removed in earlier years will benefit those living in 2018. Since there is broad agreement to reduce mercury exposure in 2018, there must be agreement that cost effective earlier reduction of mercury is also desirable. The problem is that there is great disagreement on what will be cost effective when.

The proposed rule attempts to allay power plant concerns about cost through a "safety valve" provision. A 34 ton cap is proposed for 2010. 68,000 pounds of mercury allowances would be allocated to the 300,000 MW of generating capacity. The average 300 MW plant would have an allowance of 68 pounds. Should he emit more than 68 lbs in 2010 he can buy allowances on the open market. If he cannot buy allowances on the open market for less he can buy them from EPA for $35,000/lb. The average 300 MW plant emits 96 lbs/yr of mercury. Therefore the worst case scenario is a 2010 cost of 28 lbs x $35,000 = $980,000.

Impasse Analysis: There is no supplier with deep pockets guaranteeing to remove 90 percent of the mercury at $5,000/lb of mercury in 2007. So while environmentalists claim that this can be done utilities can justifiably ask: what if we install lots of equipment which does not work and then still end up not meeting the limits? They argue that by 2018 solutions will be available at a reasonable cost. So let's wait.

Argument over an unknown is fatal to any progress. Since the cost of removal at any point in time is not certain, progress can only be made by eliminating the

relevance of this "unknown." Variable safety valve allowance pricing does precisely this.

Proposition Details: The safety valve concept is undeniably a positive addition. Environmentalists who anticipate allowances selling for $5,000/lb will not object to a $35,000 safety valve price. Utilities which anticipate much higher costs are relieved that there is a cost ceiling. But this high priced safety valve which is only applicable at a 34 ton cap in 2010 does little to break the impasse. However, the basic idea can be exploited to completely eliminate the Impasse.

The plan entails a fixed cap with variable price allowances. Under this proposal the ultimate cap, whether it is 5 tons or 10 tons, would be utilized from the first date of promulgation. This means that the average 300 MW utility would have an allowance of 10 to 20 pounds from some date starting in 2006 through 2010. The plant would buy allowances for yearly emissions above this figure. However, if the allowances exceeded some price, e.g. $1,000-5,000 in the first year, they could be purchased for that amount from EPA. This price would rise each year. So for example the price could start at $1,000/lb in 2007 and rise to $7,000/lb in 2010. A 2018 price of $25,000/lb instead of the proposal of $35,000 could be set.

This mechanism favors all parties. Environmentalists who are confident that 90 percent removal will be achieved at $5,000 lb would back a variable price at this amount at the earliest time they can negotiate. Utilities who are already anticipating spending up to $35,000/lb in 2018 will see themselves much better off under this provision. Suppliers will be spurred to massive R and D programs because they can target specific years when they are confident their technology will be more cost effective than the safety valve price. The public will be better off because the private sector will shoulder the development costs. EPA and DOE will be relieved that the burdens are transferred elsewhere.

Summary: The fixed cap/variable safety valve allowance prices for mercury would eliminate the impasse in Clear Skies passage and would result in a very cost effective solution to the mercury removal problem. Since many suppliers believe they have solutions which will remove mercury at low cost, but who do not see any market until 2018, this provision would trigger immediate development of technology. In the past, government funded development of air pollution control technology has proven to be expensive and not as productive as private funding. Revenues generated by the safety valve option could be funneled directly to mercury technology development. So this provision will be an important addition to the proposed legislation.

The commenter then offered an example of how the variable mercury safety valve plan would work for a 300 MW plant.

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble.

Comment:

One commenter (OAR-2002-0056-2918) believed that an enhanced, appropriately designed "Safety Valve" provision could resolve several critical problems related to implementation of a mercury cap and trade program for the coal-fired power plant industry. The commenter stated a properly designed safety valve mechanism could ensure compliance with, and the integrity of, the Phase I (2010) and Phase II (2018) mercury emission caps while providing the flexibility to address the current uncertainty about mercury emissions and their control.

The commenter proposed that EPA enhance the safety valve provision and design it to address the following critical cap and trade implementation issues:

- Significant uncertainty exists over the accuracy of EPA's ICR and NATEMIS national emissions database inventories, as well as the accuracy of EPA's 34-ton co-benefits-based Phase I mercury emissions cap. Therefore, the coal-fired power plant industry sees significant uncertainty whether sufficient mercury allowances will be available for compliance after the co-benefit controls are installed under EPA's proposed CAIR.

- In addition to the potential Phase I shortfall of mercury allowances, the compliance issue is exacerbated for one or more coal ranks if EPA's allowance multipliers are not set appropriately.

- EPA's proposed confiscation of future year "borrowed" mercury allowances in its safety valve proposal presents serious potential system reliability and future compliance problems. As currently understood by industry, if significant advancements in mercury control technology do not develop at a commercial level by Phase II (2018), the confiscation of future year allowances will simply "dig the hole deeper."

- Finally, the safety valve needs to materially contribute to actual achievement of the Phase II 15 ton/yr mercury emissions cap. The commenter prepared a "Hg Co-Benefits and CSA Phase I and II Analysis" that demonstrated (based on EPA's ICR II and NATEMIS national emissions inventory data) that after application of co-benefit control technology required to meet the CSA requirements, and with the application of all feasible ACI mercury control (assuming it becomes commercially available), national mercury emissions from power plants would remain at about 19 tons/year by Phase II.

The commenter believed that a safety valve must be properly designed to maximize mercury emission reductions, while enabling the operators of coal-fired power plants to comply with the Phase I and Phase II caps at an acceptable cost. The commenter submitted that a properly designed safety valve could also accelerate the development of commercially available mercury control technologies necessary to achieve the proposed Phase II 15 ton/year cap. The commenter stated that the aforementioned co-benefits analysis was performed principally with the use of EPA's IPM modeling assumptions about the effectiveness of mercury control technologies, including ACI.

The commenter recommended that EPA revise its proposed safety valve provision to include the following design elements for both Phase I and Phase II of the mercury cap and trade program:

- Allow a lower $/lb mercury safety valve fee for compliance during Phase I (2010-2017). The safety valve fee during Phase I could be set at $15,000 per pound. Covered facilities would pay the fee in lieu of using mercury allowances for compliance in the event that the mercury allowance price exceeds $15,000 per pound.

- Allow payment of EPA's currently proposed $35,000/lb fee during Phase II, in lieu of using mercury allowances for compliance in the event that the allowance market price exceeds $35,000 per pound.

- Do not confiscate future year mercury allowances under either the Phase I cap, or under the Phase II cap. Facilities paying the fee would not be allowed to use any Phase I or Phase II "banked" emission credits. This feature would ensure that banked emissions must be used, or placed on the market (likely at a price lower than the fee), before compliance is allowed by payment of the safety valve fee, to preserve the integrity of the mercury caps to the maximum extent possible.

- Establish a Mercurv Reduction Fund from the safety valve fees collected, and disburse the funds (with no more than a 5percent administrative cost) to achieve mercury reductions and advancing mercury control technologies, by contracting for and funding: (1) Project proposals to make mercury reductions from other mercury emissions sources "off the utility system"; and, (2) Project proposals that demonstrate advanced mercury control technologies, including commercial level generating unit demonstrations (i.e., units at 25MW to 750MW capacity).

- Conduct a mercury cap and trade program "reasonable progress" review at years 2015, 2018, and 2021 to assess the actual mercury emissions reduction progress occurring from electric generating units (EGUs) under the cap and trade program, compared with the Phase I and Phase II mercury caps. The purpose of a "reasonable progress" review would be to determine whether any program adjustments need to be promulgated by rule revision, to ensure that the mercury reduction caps are achieved–given the state of development of mercury emission reduction technologies, and the reliability of the national electric supply grid system.

The commenter stated that the safety valve proposal would guarantee a maximum price at which regulated sources would be able to purchase mercury allowances for Phase I and Phase II, market pressures notwithstanding. The safety valve also would minimize unanticipated allowance market volatility by ensuring that the price for allowances would not exceed a fixed ceiling. According to the commenter, EPA thereby would provide industry with reliable market information for strategic compliance planning. Even more importantly, in the event that it proved more costly and difficult to achieve the Phase I and Phase II mercury emissions reduction targets than is now projected, the marginal cost of the mercury control program could not exceed $15,000 per pound in Phase I and $35,000 per pound in Phase II. The commenter stated that this would protect consumers from unanticipated and unjustifiable costs. For these reasons, the commenter supported the creation of a safety valve mechanism for both Phase I and Phase II of the proposed mercury cap and trade program to ensure that emissions reductions will be achieved, but that control costs would not exceed a predetermined level.

The commenter further supported the creation of a Mercury Reduction Fund as an effective means for maximizing the economic efficiency of achieving the Phase I and Phase II mercury reduction caps. First, safety valve funds could be used to stimulate the development of innovative control technologies, by providing capital to potential innovators that is otherwise unavailable due to the scale of the required investment, the delay in return, or the degree of risk involved. Second, the fund could act as a safety net or relief valve by making it easy for sources with limited or no emissions control capability to obtain needed reductions from off-line sources that can reduce emissions more efficiently.

The commenter pointed out that a safety valve fund could enhance compliance with emissions standards in several ways. The commenter continued that the fund also would promote regulatory certainty by guaranteeing a cap on removal costs. This would help owners and operators of regulated sources better plan for the future. The commenter submitted that the fund also would enable EPA to target sources for cost-effective emissions reductions that EPA otherwise would lack the statutory authority to regulate. Armed with safety valve funds, the commenter believed EPA could act as a market participant and procure additional reductions from any entity willing to be paid in return.

The commenter added that a safety valve fund could also significantly benefit the environment. For example, if the safety valve were set at an appropriate marginal control cost level as described above, regulated sources would be discouraged from paying into the fund to cover emissions. Rather, sources would be encouraged to develop innovative ways to reduce emissions more efficiently. Further, the commenter stated a safety valve fund would encourage the aggregation of capital for larger, strategic investments by reducing associated transaction costs. The commenter suggested EPA could then use the capital at its disposal to invest in a variety of technological innovations, including low-risk, low-return investments as well as higher-risk and potentially higher-return investments.

In conclusion, the commenter urged EPA to establish Phase I and Phase II safety valve fees at appropriate marginal cost level (as proposed above) that would be high enough to discourage sources from choosing payment into the fund as their means of control, but low

enough so sources that could not obtain controls for a reasonable cost would not be penalized. The commenter further recommended that EPA use safety valve proceeds to purchase additional cost-effective off-utility (EGU) sector reductions, not to purchase or confiscate mercury allowances from future years. By implementing the recommended safety valve provision, the commenter believed EPA could prevent delay in important air quality achievements. Moreover, the commenter supported the use of any excess safety valve funds to provide capital for the development of better, more efficient mercury controls.

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble.

Comment:

One commenter supported the proposed safety valve price level as a means of capping the overall economic impact of controlling mercury emissions. The commenter submitted the price cap would be critical considering that there is no commercially demonstrated control technology. The commenter agreed that EPA's cap-and-trade program would effectively address alleged mercury hot spots and concluded that most cost-effective reductions will be made at the larger, higher emitting sources. The commenter also agreed the remaining uncontrolled emissions would be largely elemental mercury that is not as likely to be deposited locally as is the particulate and oxidized mercury. (69 FR 4703.)

However, the commenter was unclear how a safety valve would be an effective tool to minimize unanticipated market volatility if the future year cap were reduced by the borrowed amount. The commenter believed that while it may alleviate compliance concerns, at some point in time triggering the safety valve in multiple years could compound future compliance requirements unless industry were able to effectively reduce future mercury emissions within a reasonable time frame.

The commenter recommended that if the safety valve is triggered, the annual allocations to the plant withdrawing from the safety valve pool should be decreased at a rate of 0.5 ounces for every ounce of mercury it purchased under the safety valve. (69 FR 4704.)

Response:

EPA is not finalizing a safety valve provision in CAMR. EPA maintains that the safety valve mechanism is not necessary to address market volatility associated with the Hg reduction requirements. This issue is discussed in detail in section IV of today's preamble.

5.8.3 Early Reduction Credits and Incentive Pools

Comment:

One commenter (OAR-2002-0056-3531) further suggested, if the EPA were to create an early reduction credit program, significant reductions prior to 2010 would still be achieved by units coming on line early to earn the ERCs. The commenter concluded that as a result, early mercury reductions will be achieved while still allowing for a reasonable cost effective installation schedule.

Response:

The first phase Hg cap is set at a level that requires no additional installation of controls relative to CAIR, because it is set at a level that represents projected cobenefit mercury reductions that will occur as a result of NO_x and SO_2 control technologies installed under CAIR. Acid Rain Program units and SIP call units can bank excess NO_x and SO_2 reductions achieved prior to 2010 for use under CAIR. Further, EPA is finalizing that banking be allowed without restriction from the start of the Hg cap-and-trade program. Banking of allowances will provide flexibility to sources, encourage earlier or greater reductions than required, stimulate the market, and encourage efficiency.

Comment:

One commenter (OAR-2002-0056-3444) stated that the proposed initial compliance date of 2010 creates a large uncertainty in the ability of the Electric Generating Industry to achieve the reductions required by the initial mercury cap. To assist the industry and the EPA in achieving these target reductions the commenter believed it would be necessary to implement an Early Reduction Credit (ERC) program to create incentives for coal fired Utility Units to install controls well before the 2010 target date. The commenter submitted that to effectively achieve early mercury reductions the following elements should be part of the proposed ERC program: 1) Installation of controls must be accomplished prior to 2009; 2) Continuous Mercury Emissions Monitoring Systems must be installed with a minimum demonstrated data availability of 90 percent; 3) Installed control efficiency must meet or exceed the co-benefit removal efficiency target for the type of coal being combusted; 4) ERC's allocated to sources must be used prior to the 2018 final budget compliance date.

Response:

The first phase Hg cap is set at a level that requires no additional installation of controls relative to CAIR, because it is set at a level that represents projected cobenefit mercury reductions that will occur as a result of NO_x and SO_2 control technologies installed under CAIR. Acid Rain Program units and SIP call units can bank excess NO_x and SO_2 reductions achieved prior to 2010 for use under CAIR, and sources will be allowed to bank starting at beginning of the first phase of the Hg cap-and-trade program.

Comment:

One commenter (OAR-2002-0056-4891) added emissions reductions credits should be provided to facilities subject to the rule for commissioning projects that achieve mercury emissions reductions from other mercury emission sources.

Response:

The ability to accurately measure emissions reductions, and thus guarantee the value of an allowance, is essential to a successful cap-and-trade program. Allowing credit to be used in the Hg cap-and-trade program for utilities from off-sector reductions that may not have adequate Hg emissions monitoring, would jeopardize the certainty behind the value of an allowance, and thus the functioning of the trading program.

Comment:

One commenter (OAR-2002-0056-3446) recommended that EPA develop a technology incentive pool, a mechanism in which allowances from the first compliance period would be distributed early to plants that deploy advanced mercury control technology. This would spread the risks of technology development and help build confidence in the performance and cost of advanced control technologies. The commenter stated that an IPM modeling run found a 2.6 ton/yr incentive pool (with a 26-ton Phase I cap and a 15-ton Phase II cap) would achieve a total penetration of 31 GW of ACI in 2010 and 48 GW of ACI in 2015–11 and 5 GW of ACI penetration more than a program with no technology incentive pool. The commenter added that this added technology penetration would be achieved at an incremental net present value cost of $400 million or 0.6 percent of total 3-pollutant compliance costs.

Response:

While the proposed technology incentive pool has merit for the potential to stimulate earlier adoption of Hg control technology, EPA believes that the market forces at work under the Hg cap-and-trade program will act to promote the development of Hg control technology, and the technology incentive pool is not necessary.

Comment: Several commenters (OAR-2002-0056-2181, 2519) noted the EPA has indicated that it is examining a possible incentive within the cap and trade program that would provide and set aside allowances that would be used to develop so called “technology incentive pools.” EPA appears particularly concerned with providing a technology assist for the development and deployment of activated carbon injection (ACI) systems. The commenters had serious concerns about applying such a system in the context of a cap and trade program because it would conflict with the goal of a system that allows market forces to set the cost of compliance. The commenters stated that in a trading program, an appropriately set cap should be the signal that will drive the appropriate economic response, which may include any number of market driven reactions, such as new technology investments, fuel choices or efficiency standards. One of the primary advantages of the cap and trade approach is the ability to drive the

development of new technology solutions that are not foreseen in the program design. The commenters believed that any technology set-aside within the context of a trading program would tend to predetermine an economic outcome, generally at the expense of alternative choices that may provide consumers with lower cost solutions, a more aggressive environmental benefit, or both. The commenters submitted that this has been well documented in earlier cap and trade programs in which new and lower cost solutions that were not expected or predicted during the program design period successfully evolved and were deployed. The future success of the program should not be constrained by trying to anticipate future technology or market solutions. The commenters stated the program will find the right answers if it is designed to treat all sources equally and reward efficiency and low emissions.

Response:

While the proposed technology incentive pool has merit for the potential to stimulate earlier adoption of Hg control technology, EPA believes that the market forces at work under the Hg cap-and-trade program will act to promote the development of Hg control technology, and the technology incentive pool is not necessary.

Comment:

Many commenters (OAR-2002-0056-1608, -1673, -1814, -2163, -2180, -2224, -2375, -2718, -2725, -2835, -2843, -2845, -2850, -2861, -2862, -2900, -2907, -2922, -2948, -2951, -3431, -3444, -3521, -4132) suggested that EPA should provide for early reduction credits. One commenter (OAR-2002-0056-2180) stated that to encourage development and implementation of technologies that reduce mercury emissions, and to help insure a workable cap and trade program, there should be a crediting program for early mercury reductions. One commenter (OAR-2002-0056-2725) believed that early reductions reduce the overall mercury loading in the environment and, to the extent power plant reductions will have a positive impact on public health, achieve those benefits earlier. In particular, for the proposed trading program, the commenter supported setting the "baseline" from which reductions will be measured at an earlier date and protecting the ability to bank allowances throughout the program.

Response:

EPA is not finalizing an early reduction program. The first phase Hg cap is set at a level that requires no additional installation of controls relative to CAIR, because it is set at a level that represents projected cobenefit mercury reductions that will occur as a result of NO_x and SO_2 control technologies installed under CAIR. Acid Rain Program units and SIP call units can bank excess NO_x and SO_2 reductions achieved prior to 2010 for use under CAIR, and sources will be allowed to bank starting at beginning of the first phase of the Hg cap-and-trade program. EPA believes that the cap-and-trade program, by relying on market forces, will provide incentives for the development of mercury control technologies.

Comment:

Several commenters (OAR-2002-0056-2862, -2922) supported the creation of an early reduction credit feature as part of the mercury trading program to aid in the development of mercury emissions control technologies. One commenter (OAR-2002-0056-2922) stated that EPA should create a small reserve of early reduction credits for units that install mercury-specific control technology by 2014. The commenters (OAR-2002-0056-2862, -2922) submitted that EPA should limit the program to mercury-specific controls; no credits should be given for the installation of scrubbers, SCRs, or other controls designed primarily to reduce emissions of NO_x, SO_2, or other non-mercury emissions. The commenters believed EPA should award credits only for reductions of mercury emissions that result from mercury-specific controls that go beyond the reductions achieved as co-benefits from NO_x or SO_2 controls.

Response:

EPA is not finalizing an early reduction program. EPA believes that the cap-and-trade program, by relying on market forces, will provide incentives for the development of mercury control technologies. Additionally, the ability of sources to bank allowances starting at the beginning of the Hg cap-and-trade program, will provide flexibility to sources, encourage earlier or greater reductions than required, stimulate the market, and encourage efficiency.

Comment:

Commenter OAR-2002-0056-2861 stated that under the recommended alternate cap and trade proposal (first cap and allocations begin in 2015), the commenter recommended an early reduction credit program that provides credit only for reductions attributed to technologies designed specifically to capture mercury. The utility would provide a demonstration of the removal efficiency and would be provided credit for the difference between actual mercury emissions and emissions that would have occurred without the use of the technology. The commenter suggested the operating permit would specify conditions to verify control technology performance.

If EPA establishes a cap and trade program that begins in 2010, then commenter OAR-2002-0056-2861 believed an early reduction credit program would be even more important and should include credit for reductions achieved as a co-benefit of SO_2 and NO_x controls. The commenter suggested that in order to earn early reduction credits, EPA would need to require only that the facility install appropriate monitoring technology to quantify emissions and the level of mercury removal resulting from the installation of emission controls for SO_2 and NO_x or demonstration technologies specifically aimed at removing mercury. The commenter noted that the level of "co-benefits" associated with SO_2 and NO_x controls is uncertain and variable, and utilities will need to work with the technologies to develop ways to enhance their removal efficiencies. The commenter submitted that compliance by 2010 will also be very difficult, and providing an early reduction credit program will help facilitate compliance while preserving the nation's fuel diversity. Early reduction credits would provide an incentive for companies to install and operate emissions controls and achieve reductions sooner than they otherwise would.

The commenter suggested that if EPA has concerns that too many early reduction credits would be banked, it can create a "Compliance Supplement Pool" similar to the program used in the NO_x SIP Call, thus limiting the number of allowances that could be earned through early reductions.

Response:

EPA is not finalizing an early reduction program. The first phase Hg cap is set at a level that requires no additional installation of controls relative to CAIR, because it is set at a level that represents projected cobenefit mercury reductions that will occur as a result of NO_x and SO_2 control technologies installed under CAIR. Acid Rain Program units and SIP call units can bank excess NO_x and SO_2 reductions achieved prior to 2010 for use under CAIR, and sources will be allowed to bank starting at beginning of the first phase of the Hg cap-and-trade program.

Comment:

Several other commenters (OAR-2002-0056-1608, -2850, -3521) also stated that EPA should provide early reduction credits for mercury-specific add-on controls. Several of these commenters (OAR-2002-0056-2907, -3521) stated early reduction credits should be awarded units that implement mercury-specific controls prior to 2015. Several of these commenters (OAR-2002-0056-2907, -2850) also supported early reduction credits for coal plant closures. Similarly, one commenter (OAR-2002-0056-4132) stated that EPA must provide early reduction credits for plants shutting down. The commenter noted that the economic burden of this mercury initiative may force the shutdown of some of the oldest EGUS. If these units shutdown, yielding early reductions in mercury emissions, it is important that early reduction credits be provided. The commenter emphasized that the final regulations should expressly and properly acknowledge this approach to early reductions.

Response:

EPA is not finalizing an early reduction program. EPA believes that the cap-and-trade program, by relying on market forces, will provide incentives for the development of mercury control technologies. Additionally, the ability of sources to bank allowances starting at the beginning of the Hg cap-and-trade program, will provide flexibility to sources, encourage earlier or greater reductions than required, stimulate the market, and encourage efficiency. Further, EPA is not projecting that any additional coal-fired capacity will be uneconomic to maintain relative to CAIR under the combination of CAIR and CAMR.

Comment:

One commenter (OAR-2002-0056-1673) stated that the IAQR and mercury rules should provide utilities with the incentive to undertake early reduction measures, such as year round operation of SCRs currently operated during the ozone season. This would provide immediate NO_x and mercury reduction benefits. Another commenter (OAR-2002-0056-1814) submitted that early reduction credits would provide an incentive for companies to install and operate emissions controls and achieve these co-benefits earlier. The commenter believes these credits

are also important in aiding companies in meeting very aggressive schedules for installation of equipment. A third commenter (OAR-2002-0056-2845) stated that credits for early reductions could be coupled with additional early SO_2 reductions in the CAIR proposal. The commenter believed the proposed rule should provide credit for reductions achieved from the installation and/or modification of emission or combustion control technologies like early installation and operation of scrubbers, SCR, and ACI. The commenter stated that credit should not be available for reductions required under federal regulations.

Response:

EPA is not finalizing an early reduction program. The first phase Hg cap is set at a level that requires no additional installation of controls relative to CAIR, because it is set at a level that represents projected cobenefit mercury reductions that will occur as a result of NO_x and SO_2 control technologies installed under CAIR. Acid Rain Program units and SIP call units can bank excess NO_x and SO_2 reductions achieved prior to 2010 for use under CAIR, and sources will be allowed to bank starting at beginning of the first phase of the Hg cap-and-trade program. See *the CAIR preamble for discussion of early reduction credits under that rule.*

Comment:

Several commenters (OAR-2002-0056-2224, -2835) noted that an early reduction credit system is consistent with the concept of "banking" surplus reductions under a market-based, cap-and-trade regulatory approach. Commenter OAR-2002-0056-2224 noted that in order to facilitate this action, details pertaining to the baseline, measurement, deadline and time line mechanisms would need to be sorted out in the final rule. Commenter OAR-2002-0056-2835 believed that an early reduction credit would not compromise the environmental integrity of the trading program because only a small number of sources would be able to take advantage of this feature. According to the commenters, from a policy perspective, early mercury reductions should be encouraged because they deliver an important environment benefit in advance of the regulatory control program. The commenters further added that credit should only be granted where a facility can demonstrate that the reductions are real and quantifiable. The commenter also added that any early reduction credit scheme should not penalize a facility for such reductions by reducing the allocations the facility would receive under the trading program.

Response:

EPA is not finalizing an early reduction program. The first phase Hg cap is set at a level that requires no additional installation of controls relative to CAIR, because it is set at a level that represents projected cobenefit mercury reductions that will occur as a result of NO_x and SO_2 control technologies installed under CAIR.

Comment:

One commenter (OAR-2002-0056-2163) noted that cost-effective implementation of any new technology requires experience with full-scale installations over extended periods of

operation. The commenter stated there are always forward-thinking utilities who are interested in early adoption of new pollution control strategies. The commenter believed these utilities should be offered incentives to promote this early adoption strategy and to encourage the refinement and deployment of control technology options. Such incentives could include bankable and/or salable emissions credits. The commenter strongly encouraged EPA to work with these early adopters to creatively develop a strategy that offers broad incentives for early implementation.

Response:

EPA believes that the market forces at work under the Hg cap-and-trade program will provide incentives for the development of Hg control technology. This incentive will be further strengthened by the ability of sources to bank allowances from excess mercury reductions starting at the beginning of the Hg cap-and-trade program.

Several commenters (OAR-2002-0056-2375, -2718) proposed that sources be able to earn ERCs before the Phase I deadline in 2010. To address concerns that such a provision may jeopardize the integrity of the Phase I and Phase II caps, commenter OAR-2002-0056-2375 submitted that ERCs should be discounted at a 2-to-1 ratio upon registration into the mercury bank. Sources would be permitted to use ERCs without discount during Phase I and Phase II. The commenter (OAR-2002-0056-2375) asserted that an ERC program is supportable on public policy grounds. The commenter believed an ERC provision in the final rule would encourage sources not yet equipped with mercury controls to install and operate them before the January 2010 deadline, where feasible, so that greater reductions would be achieved earlier. The commenter's proposal that ERCs be discounted at a 2-to-1 rate upon registration in the mercury bank would achieve added benefits by ensuring that sources would be permitted to emit only one ounce of mercury after Phase I takes effect for every two ounces of mercury reduced prior to January 2010. The commenter believed in addition, an ERC provision would provide sources with much-needed compliance flexibility for meeting the Phase I deadline. Similarly, commenter 2718 proposed that affected sources that implement mercury CEMs monitoring be permitted to earn ERCs at a 2-to-1 ratio such that one credit would issue for every two ounces of mercury emissions reduced from the source's baseline. Sources using other methods, such as stack testing or look-up tables, would be subject to a 3-to-1 issuance ratio.

Response:

EPA is not finalizing an early reduction program. EPA believes that the cap-and-trade program, by relying on market forces, will provide incentives for the development of mercury control technologies. Additionally, the ability of sources to bank allowances starting at the beginning of the Hg cap-and-trade program, will provide flexibility to sources, encourage earlier or greater reductions than required, stimulate the market, and encourage efficiency.

One commenter (OAR-2002-0056-2907) participated in programs to voluntarily reduce emissions from its facilities prior to adoption of mandatory programs. The commenter believed EPA should not penalize the commenter's efforts and the efforts of similar proactive companies

by reducing mercury allowance allocations to companies that make emission reductions prior to the compliance dates required by this rule. Instead, EPA should encourage and support early reductions by not restricting the banking of allowances created by early reduction programs. The commenter believed all reductions completed prior to the compliance date should be credited toward meeting the proposed cap.

Response:

EPA is not finalizing an early reduction program. The first phase Hg cap is set at a level that requires no additional installation of controls relative to CAIR, because it is set at a level that represents projected cobenefit mercury reductions that will occur as a result of NO_x and SO_2 control technologies installed under CAIR. Acid Rain Program units and SIP call units can bank excess NO_x and SO_2 reductions achieved prior to 2010 for use under CAIR, and sources will be allowed to bank starting at beginning of the first phase of the Hg cap-and-trade program. See *the CAIR preamble for discussion of early reduction credits under that rule.*

Comment:

One commenter (OAR-2002-0056-2900) noted that Phase I of the Program is scheduled to begin in 2010, to coincide with the first phase of the CAIR. In addition, EPA proposes to set the Phase I mercury cap according to the co-benefits achieved from the SO_2 and NO_x reductions mandated by the CAIR. However, it is not clear to the commenter what that level should be and, if EPA is mistaken in the level of the Phase I mercury cap, it is possible that coal-fired EGUs will not meet the cap even with the installation of stringent SO_2 and NO_x controls on each affected unit. To alleviate this potential problem, the commenter recommended that EPA allow coal-fired EGUs to generate early reduction credits that could be used during Phase 1. Specifically, the commenter recommended that EPA grant mercury early reduction credits to sources that demonstrate that their mercury emissions are below the amount they are allocated under Phase 1. The commenter also recommended sources should be allowed to generate early reduction credits beginning with adoption of the Program until the start of Phase I, unless the units are retired or repowered. They would not be eligible for early reduction credits until they have met the Program's initial certification procedures for mercury monitoring.

Response:

EPA is not finalizing an early reduction program. The first phase Hg cap is set at a level that requires no additional installation of controls relative to CAIR, because it is set at a level that represents projected cobenefit mercury reductions that will occur as a result of NO_x and SO_2 control technologies installed under CAIR. Acid Rain Program units and SIP call units can bank excess NO_x and SO_2 reductions achieved prior to 2010 for use under CAIR, and sources will be allowed to bank starting at beginning of the first phase of the Hg cap-and-trade program. See *the CAIR preamble for discussion of early reduction credits under that rule.*

Comment:

To ensure that such early reduction credits would not simply expand the Phase I cap and indefinitely put off achievement of the Phase II cap, the commenter (OAR-2002-0056-2900) suggested that such early reduction credits expire in 2014, although the commenter advocated unlimited banking for mercury allowances that are allocated to affected sources under each phase of the program. The commenter believed that early reduction credits would help sources make the transition to the Program. They also would improve the robustness of the market and would offer EUSGUs an incentive to achieve reductions earlier than otherwise required. Finally, the commenter believed early reduction credits will help avoid the need for sources to use the safety valve that the Agency is proposing.

Response:

EPA is not finalizing an early reduction program. The first phase Hg cap is set at a level that requires no additional installation of controls relative to CAIR, because it is set at a level that represents projected cobenefit mercury reductions that will occur as a result of NO_x and SO_2 control technologies installed under CAIR. Additionally, the ability of sources to bank allowances starting at the beginning of the Hg cap-and-trade program, will provide flexibility to sources, encourage earlier or greater reductions than required, stimulate the market, and encourage efficiency.

Comment:

One commenter (OAR-2002-0056-2951) stated that to maximize the social benefits from utility mercury emission limitations, the regulatory scheme needs the earliest possible compliance date. The commenter called this the "Average Control Date." The commenter added that just as important, to minimize social costs we need the earliest possible date that utilities can get credit for making technology-based mercury reductions. The commenter called this the "Mercury Credit Date."

The commenter stated that on their own, utilities have no incentives to reduce any mercury emissions one minute before they have to. The commenter added that indeed, top utility executives could be sued by their shareholders if they spent any money on mercury reductions any earlier than required; that money should theoretically go to the shareholders.

The commenter stated that nationally, it is obviously advantageous to have orderly mercury technology implementation, rather than the inefficiencies resulting from all of the utilities and their subcontractors competing to have controls in place on all 1,100 boilers at the same date. The commenter believed, however, that social benefits are lost with any delay. The commenter stated that, consequently, utilities should be able to make mercury reductions at some of their units early, ahead of the Average Control Date, and get credit that they can trade off by beginning reductions at an equivalent amount of their units late. According to the commenter, as net mercury emissions would be the same, society should be largely indifferent to such

"banking." The commenter believed if the tougher, more-costly sites come last, society even gains a bit.

The commenter suggested that to maximize the benefits of such flexibility, the temporal trade-off period should be designed to be as wide as possible (and it need not necessarily be symmetrical). The commenter stated that in particular, it should begin at the earliest conceivable "Mercury Credit Date" because any early technology-adopters benefit everyone else by leading the industry down the learning curve, resulting in lower total costs for everyone. The commenter added that unfortunately, however, any early adopters would inevitably see higher costs and greater risks than those who wait until the last minute, and they would be unable to capture the social benefits of their pioneering, thus creating a classical market failure.

The commenter stated that consequently, there should be special incentives for early technology-based mercury-reductions. The commenter added that for example, early technology-driven mercury reductions could receive extra credit, perhaps at 2X, for banking purposes. The commenter stressed that the positive social externalities of early technology adopters are very real and very significant and efforts should be made to encourage them in constructing any utility mercury regulatory framework.

The commenter further stated that there are no positive externalities with early switches to lower-Hg-coal or for scrubbing co-benefit-based-reductions or other non-innovative-technology-based Hg reductions. According to the commenter, while these types of reductions could conceivably be banked, they might be difficult to substantiate or result in zero-sum losses in unobserved parts of the system. The commenter believed they should not be advantaged.

Response:

EPA believes that the cap-and-trade program, by relying on market forces, will provide incentives for the development of mercury control technologies. Additionally, the ability of sources to bank allowances starting at the beginning of the Hg cap-and-trade program, will provide flexibility to sources, encourage earlier or greater reductions than required, stimulate the market, and encourage efficiency. Therefore, EPA does not believe it is necessary to add any additional provisions to the rule to promote technology adoption.

One commenter (OAR-2002-0056-2843) stated that if a cap-and-trade program is promulgated, two essential elements must be preserved if new coal-fired units are to remain viable resources for the future. First, because compliance with either emission rates or reductions necessary under a "cap-and-trade" environment are uncertain at best, there must be a reliable and readily available source of allowances available for purchase at a pre-determined price. The commenter suggested that early reduction credits might be an available resource for these allowances. Second, the commenter believed there should be a reservation of allowances for allocation to new units. These should be available on a first-come, first-served basis until exhausted.

Response:

EPA is not finalizing an early reduction program. The first phase Hg cap is set at a level that requires no additional installation of controls relative to CAIR, because it is set at a level that represents projected cobenefit mercury reductions that will occur as a result of NO_x and SO_2 control technologies installed under CAIR. Additionally, the ability of sources to bank allowances starting at the beginning of the Hg cap-and-trade program, will provide flexibility to sources, encourage earlier or greater reductions than required, stimulate the market, and encourage efficiency.

Under the Hg cap-and-trade program, States determine how to allocate allowances to sources. EPA provides an example allocation methodology in the model rule, which provides for a new source set-aside.

Comment:

One commenter (OAR-2002-0056-2850) achieved about 17 percent reduction in mercury stack emissions in 2000 compared to 1990 levels through optimizing fuel sourcing and plant operation. The commenter's coal units are also over 70 percent wet scrubbed for particulate and sulfur dioxide removal, which combined with other voluntary mercury reduction activities has reduced base line emissions relative to 1990 and compared to other utility units. Consequently, the commenter stated that an equitable allocation of mercury reduction requirement stringency, either through unit specific requirements or cap and trade program allowance allocation methodology would be important for assuring reasonable credit for early action. The commenter supported an equitable cap-and-trade approach as the preferred option for regulating electric power sector mercury emissions, as that provides the most flexibility for achieving compliance using new and often unproven technology.

Response:

EPA agrees with the commenter about the advantages of using cap-and-trade for achieving mercury emissions reductions from the power sector. Under the Hg cap-and-trade program, States have the authority to allocate allowances to sources. EPA's example allocation methodology is outlined in the preamble. EPA is not finalizing an early reduction credit provisions. See the comments above regarding this issue.

Comment:

One commenter (OAR-2002-0056-3431) believed the market will send the proper signals to influence early reductions that will drop mercury emissions at a sharp and steady rate as the first phase compliance deadline approaches. The commenter stated that credit for such early reductions can be patterned after the provisions of the NO_x SIP Call and NO_x budget rules and could be granted for reductions in total mercury in coal from as-fired analyses and consumption information. The commenter added that such information could be verified with annual stack testing prior to installation of Hg Continuous Emission Monitoring Systems (CEMS). According

to the commenter ERCs are a "win-win" for EPA, industry, and the environment; the opportunity to receive ERCs improves environmental performance, reduces cumulative compliance costs and provides flexibility to deal with uncertainty in the trading market.

Response:

EPA is not finalizing an early reduction program. The first phase Hg cap is set at a level that requires no additional installation of controls relative to CAIR, because it is set at a level that represents projected cobenefit mercury reductions that will occur as a result of NO_x and SO_2 control technologies installed under CAIR. Additionally, the ability of sources to bank allowances starting at the beginning of the Hg cap-and-trade program, will provide flexibility to sources, encourage earlier or greater reductions than required, stimulate the market, and encourage efficiency.

Comment:

One commenter (OAR-2002-0056-2067) stated that the proposed alternative Cap-and-Trade approach would rely heavily on achieving mercury reductions through the co-benefits of future installation of scrubbers to meet SO_2 and NO_x. The commenter added that however, the Cap-and-Trade proposal failed to take into account that there are existing Utility Units that have already achieved this Phase I reduction, and are currently operating with significantly lower mercury emissions than the industry as a whole. The commenter asserted that instead, Cap and Trade would subject these plants, such as the commenter's primary generating resource (which has been controlling mercury emissions for nearly 25 years), to the same cap as the majority of Utility Units and provide allocations based on the assumption that existing scrubbers do not exist, creating an unrealistically low emissions level. The commenter stated that Cap and Trade would fail to give appropriate credit to power plants that already are reducing mercury emissions, and that indeed, it would create a greater burden on scrubbed plants because it would effectively require scrubbed plants to achieve the same level of reductions as unscrubbed plants. The commenter stated that this is a significant issue in the western United States where it has been estimated that up to two-thirds of Utility Units are presently scrubbed. According to the commenter, this approach imposes a disproportionately high burden on power plants that are already scrubbed, such as the commenter's primary generating resource, and is a fundamental flaw of Cap and Trade that is avoided under MACT.

The commenter stated that, in the event EPA selects the Cap-and-Trade approach to regulating mercury, key modifications would be necessary to make Cap and Trade workable. According to the commenter, the net effect is that while Cap and Trade is designed to achieve a total reduction of 70 percent from current levels, units that have existing scrubbers will be required to achieve this 70 percent reduction on top of existing reductions of nearly 70 percent. The commenter stated that it is fundamentally unfair for the EPA to give credit for mercury reductions to utilities that install scrubbers for SO_2 and NO_x in the future, while not providing the same credit to those who installed the technology and have been reducing emissions for 25 years. The commenter asserted that in the event EPA adopts a Cap and Trade approach, EPA should address this fundamental unfairness that would penalize utilities that have taken early steps to

reduce emissions. The commenter recommended that, at a minimum, Utility Units that have existing scrubbers should be exempt from mercury reduction requirements through Phase I, and should only be subjected to additional requirements in Phase II when the future co-benefits have been recognized, and the next level of control is required.

Response:

EPA is not finalizing an early reduction program. The first phase Hg cap is set at a level that requires no additional installation of controls relative to CAIR, because it is set at a level that represents projected cobenefit mercury reductions that will occur as a result of NO_x and SO_2 control technologies installed under CAIR. Acid Rain Program units can bank excess SO_2 reductions achieved prior to 2010 for use under CAIR, and sources will be allowed to bank starting at beginning of the first phase of the Hg cap-and-trade program. See *the CAIR preamble for discussion of early reduction credits under that rule.*

Comment:

One commenter (OAR-2002-0056-3469) recommended that EPA should implement a vigorous research and development program to develop economically viable technology solutions–and allow work on existing programs to be concluded–for all fuel sub-categories.

Response:

EPA's Office of Research and Development currently participates in a program with Department of Energy and industry representatives to assess mercury control technology options. See the revised ORD White Paper on Hg control technology, available in the docket.

Comment:

One commenter (OAR-2002-0056-4891) recommended that EPA provide an option that allows entities subject to the cap-and-trade program to "earn" emissions reduction credits for commissioning or funding projects that result in the reduction of mercury emissions from other mercury emissions point sources (e.g., fuel combustion; waste incineration; industrial processes; and metal ore roasting, refining, and processing).

Response:

The ability to accurately measure emissions reductions, and thus guarantee the value of an allowance, is essential to a successful cap-and-trade program. Allowing credit to be used in the Hg cap-and-trade program for utilities from off-sector reductions that may not have adequate Hg emissions monitoring, would jeopardize the certainty behind the value of an allowance, and thus the functioning of the trading program.

5.8.4 Other Model Trading Rule Requirements

Comment:

One commenter (OAR-2002-0056- 4139) supported the need for two primary types of accounts-compliance accounts and general accounts. Compliance accounts would be created for each Mercury Budget source with one or more Mercury Budget units upon receipt of the account certificate of representation form. General accounts would be created for any organization or individual upon receipt of a general account information form.

Response:

Today's final rule contains provisions for the establishment of compliance accounts and general accounts.

Comment:

One commenter (OAR-2002-0056-2287) suggested that the cap and trade system be open to all interested parties, including communities and environmental groups so that they could also bid for credits to use as they please.

Response:

Under the final rule, States are given the authority to allocate Hg allowances as they see fit. However, individuals and groups that are not affected sources are allowed to hold Hg allowances by establishing a general account.

Comment:

One commenter (OAR-2002-0056-3509) stated that to the extent that the final Utility Mercury Rule does require controls of small municipal generators via allowance trading or other requirements, EPA should provide these units with other compliance flexibility options to reduce the cost of such compliance. Specifically, the commenter supported several of the proposals made by EPA, including for facility-wide emissions averaging, measurement of emissions using 12-month rolling averages, the ability to bank mercury allowances without restriction, and the ability to use "safety valve" allowances when the price of allowances exceed a reasonable cost threshold.

Response:

EPA is finalizing a number of provisions as part of the cap-and-trade program in order to provide flexibility to sources. Under the final rule, compliance will be assessed at the facility level, and on a 12-month rolling average basis. Additionally, EPA is finalizing that banking be allowed without restriction, beginning at the start of the first phase of the program. EPA is not

finalizing a safety valve provision, for reasons discussed in the preamble, and section 5.8.2 of this document.

Comment:

One commenter (OAR-2002-0056-2181) believed there were several key components of the proposed rules that could set broad precedents within the electric power sector beyond just the control of mercury, specifically in regard to the design of trading programs and allowance allocation systems.

Response:

EPA believes that the final design of the Hg Budget Trading Program will result in an efficient and effective program.

Comment:

One commenter (OAR-2002-0056-2067) expressed significant concern regarding what entity actually receives the allocations in the Cap and Trade approach. The commenter stated that if a Cap and Trade alternative is selected, it is important that emission allowances be awarded to the owners of Utility Units, not the operators of such units. As a relatively small wholesale power producer, the commenter is not able to economically construct, own and operate its own baseload facilities. Rather, the commenter is a joint owner with other utilities in its primary generating resource and would expect to utilize the same type of arrangement for any future baseload coal additions to its resource portfolio. The commenter asserted that allowances should be allotted to the unit owners on the basis of their ownership interest and should not be awarded to the operators of the unit(s).

Response:

Hg allowances will be allocated by States to Hg Budget sources. Each Hg Budget source affected under the Hg cap-and-trade program is required to have 1 Hg designated representative, with regard to all matters under the trading program concerning the source or any Hg Budget unit at the source. This representative shall be selected by an agreement binding on the owners and operators of the source and all Hg Budget units at the source.

Comment:

One commenter (OAR-2002-0056-3537) stated that CAA §408(i) sets out an approach regarding the holding and distribution of Title IV SO_2 allowances and the proceeds of transactions involving allowances, where there are multiple holders of a legal or equitable title to or a leasehold interest in an affected unit. That provision in pertinent part provides that: "No permit shall be issued under this section to an affected unit until the designated representative of the owners or operators has filed a Certificate of Representation with regard to matters under this subchapter, including the holding and distribution of allowances and the proceeds of transactions

involving allowances. Where there are multiple holders of a legal or equitable title to, or a leasehold interest in such unit, or where a utility or industrial customer purchases power from an affected unit (or units) under life-of-the-unit, firm power contractual arrangements, the certificate shall state (1) that allowances, and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold or contractual reservation or entitlement, or (2) if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances, will be deemed to be held or distributed in accordance with the contract. A passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the affected unit shall not be deemed to be a holder of a legal, equitable, leasehold, or contractual interest for the purpose of holding or distributing allowances as provided in this subsection, during either the term of such leasehold or thereafter, unless expressly provided for in the leasehold agreement." CAA §408(I).

The commenter submitted that clearly, when enacting Title IV of the CAAA, Congress considered how allowances should be distributed to multiple owners of an affected unit. It concluded that allowance allocations (or the proceeds from auctions) should track the ownership interest in affected units, absent an agreement between the parties to the contrary. The commenter believed there is nothing in the proposed mercury rule that would justify following a different approach to the ultimate distribution of mercury allowances under EPA's current proposal. The commenter suggested, therefore, when proposing and promulgating regulatory language to implement the requirements of the mercury cap and trade rule, EPA should encourage States that promulgate cap and trade rules pursuant to CAA section 111 to use the approach followed in CAA §408(i) as the method for allocating allowances among multiple owners of a Utility Unit. The commenter also suggested that should EPA promulgate a cap and trade program under CAA §112, then EPA should, as part of its method for allocating allowances, follow the approach set forth in CAA §408(I).

Response:

Regarding the commenter's concerns about rules and guidance on allocations, the model trading rules already include provisions analogous to section 408(i) of the Clean Air Act.

Comment:

One commenter (OAR-2002-0056-2898) opposed EPA's proposal to confiscate future year allowances in the event a source does not have enough allowances to offset emissions. Rather, the commenter proposed that a fee be assessed for each pound of mercury that a source exceeds its available allowances. The commenter suggested this source of revenue would fund mercury control technology research and demonstration projects. The commenter added also, these monies could be used to achieve off-utility system mercury reductions.

Response:

EPA is finalizing that three Hg allowances for each ounce of emissions would be deducted from a source's compliance account for the following control period, in the event that an affected source does not hold sufficient Hg allowances to offset emissions for the season. EPA believes that it is important to set up this automatic offset deduction because it is ensures that non-compliance with the Hg emission limitations of this rule is a more expensive option than controlling emissions. EPA required the same offset deduction of three to one in the NO_x SIP call. The automatic offset provisions do not limit the ability of the permitting authority or EPA to take enforcement action under State law or the CAA.

Comment:

One commenter (OAR-2002-0056-3478) did not see the benefit to having a 3-to-l offset for allowance shortages. The commenter believed the 1-to-1 offset penalty and deduction from the next year's subaccount in Acid Rain provides adequate control for shortages.

Response:

EPA is finalizing that three Hg allowances for each ounce of emissions would be deducted from a source's compliance account for the following control period, in the event that an affected source does not hold sufficient Hg allowances to offset emissions for the season. EPA believes that it is important to set up this automatic offset deduction because it is ensures that non-compliance with the Hg emission limitations of this rule is a more expensive option than controlling emissions. EPA required the same offset deduction of three to one in the NO_x SIP call. The automatic offset provisions do not limit the ability of the permitting authority or EPA to take enforcement action under State law or the CAA.

Comment:

One commenter (OAR-2002-0056-4132) noted that EPA has proposed that the Mercury Budget Trading Program utilize source-wide compliance rather than unit-by-unit compliance. The commenter noted in particular, EPA proposed that sources would be allocated allowances rather than individual units and, accordingly compliance would be source-wide rather than unit-by-unit. The commenter strongly supported this concept. This would simplify the administrative activities associated with ensuring that each unit account has sufficient allowances by the end of the allowance transfer deadline.

Response:

EPA is finalizing that compliance with CAMR be assessed at the facility level.

Comment:

One commenter noted that EPA proposes to require compliance on a facility-wide basis rather than on a unit-by-unit basis. Each facility would have a "compliance" account, which would need to hold enough allowances to cover mercury emissions for an entire facility. The commenter believed this makes practical sense from a technology perspective, and simplifies program accounting requirements.

Response:

EPA concurs, and is finalizing that compliance with CAMR be assessed at the facility level.

Comment:

One commenter (OAR-2002-0056-4239) recommended using serial numbers of some mechanism for tracking and reporting mercury emissions. The commenter stated the program must be transparent to all entities. The commenter believed serial numbers encourage transparency and benefits derived for tax and accounting purposes.

Response:

Under CAMR, each Hg allowance will be assigned a serial number for the purpose of tracking allowances.

Comment: Several commenters (OAR-2002-0056-2634, -2830, -2835) requested that the EPA include facility-wide averaging in the section 111 Emission Guidelines for existing sources as an additional compliance alternative. States should be encouraged to allow such flexible compliance alternatives if states decline to adopt a section 111 trading program, if that option is selected by the EPA. By including this type of flexibility mechanism, the EPA will ensure that those facilities located in States opting out of the trading program will retain some degree of flexibility when complying with the requirements of the Emission Guidelines. Similarly, facility-wide emissions averaging provides a flexible compliance alternative to a cap-and-trade program in the event that neither cap-and-trade option can be authorized under the statute. Varying operational modes or combination of systems, e.g., wet/dry scrubber, ESP or fabric filter, could be employed to provide the greatest potential to economically reduce Hg emissions to meet compliance requirements.

Response:

As discussed in the final preamble, States must submit a demonstration that it will meet ist assigned emissions budget through reductions from coal-fired power plants. There are no restrictions on states using facility-wide averaging.

5.8.5 Title V Permits

Comment:

One commenter (OAR-2002-0056-4139) stated that a Title V permit incorporates applicable requirements that are created under other authorities, but does not directly establish specific standards unless explicitly provided by the CAA (such as periodic monitoring). In the case of mercury budget program requirements, the proposed rule appeared to require permitting authorities to directly create mercury permit requirements in Title V permits. The commenter questioned what authority under the CAA allows the mercury budget rule to change Title V program requirements and allow Title V to directly create mercury program permitting requirements?

One commenter (OAR-2002-0056-4139) submitted the proposed general permit requirement in 40 CFR 60.4120 specified that the Mercury Budget portion of the Title V permit is to be administered according to the permit authority's Title V operating permits regulations. However, the proposed rule did not comport with existing permit content requirements particularly for monitoring requirements. The commenter stated that the Title V permit must directly identify the applicable limits or operational restrictions and what monitoring, recordkeeping, and reporting requirements will be used to demonstrate compliance. The commenter pointed out the proposed Mercury Budget permit portion does not include that same level of detail.

One commenter (OAR-2002-0056-4139) noted the proposed general permit requirement in 40 CFR 60.4120 specifies that the Mercury Budget portion of the Title V permit is to be administered according to the permit authority's Title V operating permits regulations. The commenter submitted, however, the proposed rule did not comport with the Title V schedule requirements for revising a permit to include new requirements. The proposed general permit requirement in 40 CFR 60.4121 specified that the Mercury Budget permit application must be submitted 18 months before January 1, 2010, (or the date the Mercury Budget unit commences operation for new units). The commenter stated, however, 40 CFR 70.6(f) of the Title V operating permits rules does not require that the source submit an application to revise a Title V permit for new promulgated requirements. The permitting authority must reopen the permit for cause if there are 3 or more years remaining before the current Title V permit expires.

One commenter (OAR-2002-0056-4139) noted the proposed rule did not comport with the Title V permit renewal schedule. The proposed general permit requirement in 40 CFR 60.4121 (c) specified that the Mercury Budget authorized account representative must submit a complete mercury budget permit application according to the permitting authority's Title V operating permit regulations for permit renew. However, most of the commenter's Title V permits for the listed Mercury Budget sources will not be due for renewal during the specified Mercury Budget time frame. The commenter asked how does the Mercury Budget permit renewal synchronize with the Title V renewal schedule? The commenter found the proposed wording far too vague to adequately address the nuances of the renewal process.

One commenter (OAR-2002-0056-4139) stated that the proposed general permit requirement in 40 CFR 60.4120 specified that the Mercury Budget portion of the Title V permit is to be administered according to the permit authority's Title V operating permits regulations. All submittals pursuant to the Title V permit program must be certified by a responsible official, with specific compliance certification requirements for annual and semiannual reports. The commenter submitted, however, 40 CFR 60.4130 of the proposed rule would require data report and compliance certification submittals by the authorized account representative for different information and based on schedules that do not mesh with the Title V time frame.

Response:

Under the Hg Budget model trading rule, a Hg Budget source that is already required to have a title V operating permit is required to submit an application to the permitting authority for a Hg Budget permit, which will become a complete and separable part of the title V permit. Sources not required to have title V permits do not have to apply for Hg Budget permits. For a source required to have title V permit, the requirements of the model trading rule are applicable requirements that, under title V , must be incorporated into the source's title V permit because the requirements of the model trading rule are requirements under section 111 of the CAA. See 40 C.F.R. 70.2 (definition of "applicable requirement"). In short, contrary to the commenter's statements, the title V permit is incorporating the requirements established by the Hg model trading rule, which incorporation is analogous to the way the title V permit incorporates the requirements established by other programs (e.g., the NO_x SIP Call model trading rule) under CAA.

Comment:

One commenter (OAR-2002-0056-2922) suggested, as a general matter, that EPA pattern the mercury cap-and-trade program on the Title IV Acid Rain Program. In that regard, EPA, as it does in the Title IV program, should not require Title V operating permits to be reopened or revised for allocation, transfer, or deduction of allowances. The commenter recommended in addition, EPA should assign serial numbers to mercury allowances. The commenter believed that although tracking and reporting serial numbers would result in some administrative burden, that burden would be significantly outweighed by the benefits that serial numbers would provide for tax and accounting purposes for regulated companies and other market participants.

Response:

EPA agrees that requiring title IV operating permits to be reopened or revised for allocation, transfer, or deduction of allowances would create an unnecessary administrative burden, and is finalizing that these be automatically incorporated in the Hg budget permit. Also, EPA is assigning serial numbers to Hg allowances for the purpose of tracking.

5.9 IMPLEMENTATION

5.9.1 State Plan Requirements

Comment:

One commenter (OAR-2002-0056-2247) noted the proposed trading program would require a state to submit its first plan by 2006 for distributing allocations for 2010-2014. The commenter's state cannot meet this deadline. The commenter stated that mercury control rules and allowance distribution will be controversial; implementation will require having the legal framework in place, sufficient administrative resources, and time for input from the industry and the public. The commenter believed that at least 2 years would be needed after emission guideline promulgation to complete a rule with more time needed to actually distribute allowances. The commenter stated submittal of plans should be required at least 24 months after federal rule promulgation.

Response:

EPA is requiring a state to submit its plan for distributing allocations for 2010-2014 by October 21, 2006. As discussed in the final rule preamble, EPA believes this lead time is necessary ensures that an affected source, regardless of the State in which the unit is located, will have sufficient time to plan for compliance and implement their compliance planning.

Comment:

One commenter (OAR-2002-0056-3543) noted states would be required to submit a SIP-type plan to regulate existing mercury sources; the plan would include unit-specific standards for new units under section 111(b). It was unclear to the commenter what type of plan EPA is requesting and if it will become part of a an air quality SIP.

Response:

EPA is requiring the submission of a State plan under section 111 of the CAA. Detailed language describing the requirements of the State plan has been added to the regulatory text.

Comment:

One commenter (OAR-2002-0056-1678) submitted that relying on SIP to establish mercury reduction levels would be administratively cumbersome and time consuming and likely to result in disparate regulation.

Response:

EPA is requiring the submission of a State plan under section 111 of the CAA. Detailed language describing the requirements of the State plan has been added to the regulatory text.

EPA has provided a model rule that States can adopt in order to limit the administrative burden on States and to create a uniform program among participating States.

Comment:

One commenter (OAR-2002-0056-2841) believed that if EPA establishes a cap-and-trade program under the authority of section 112(n)(1)(A) and/or 112(d), EPA should amend the definition of "emission standard" in 40 CFR 63.2 to read "pursuant to sections 112(d), 112(h), 112(f) or 112(n) of the Act." Additionally, the commenter believed EPA should amend 40 CFR 63.1(e) to read "If the Administrator promulgates an emission standard under section 112(d), (h), or (n) of the Act. . ."

Response:

EPA is finalizing a cap-and-trade program under section 111. See preamble for more detail.

5.9.2 Approvability of Trading Rule

Comment:

Several commenters (OAR-2002-0056-2219, -2519, -3431) opposed allowing states to decide the allocation of trading units and the time line for updating the allocations. One commenter (OAR-2002-0056-2519) noted that states will have the right allocate mercury emission allowances to individual sources or to choose any other allocation scheme a state deems appropriate. In the event a state fails to submit its SIP, the model rule would become the SIP for that state. The commenter believed the SIP process could result in some sources in one state getting allowances much less than what was envisioned under the EPA's state budgets while a source in an adjoining state could receive more allowances than under the proposal. Under such a situation, the first source would have to purchase allowances from the second or apply emission controls. The commenter points out that such a scenario could result in an inefficient trading program or unfair competitive issues among sources. Furthermore, preparation and submittal of SIP must follow certain processes mandated by state Constitution, and that could result in some delay in adopting the rule governing the trading program. The commenter stated that additional time would consume part of the time allowed for compliance planning to achieve the emission caps. The commenter submitted therefore, it is critical that EPA adopt a uniform program throughout the country, much like the existing Acid Rain Control Program, rather than a patchwork of differing requirements among various states. Accordingly, if EPA decides on a cap-and-trade program rather than a MACT program, the commenter prefers the CAA section 112 approach over the CAA section 111 approach.

Another commenter (OAR-2002-0056-3431) believed a major problem with utilizing a CAA section 111 standard of performance approach to cap-and-trade would be that it requires further decision-making at the state level regarding allowance allocation. According to the commenter, the experience of the Northeast states with the NO_x budget rule, which similarly left

the intrastate allocations to the affected states, was that the allocation process was extremely contentious and subject to political influence. The commenter stated that for example, if the prevailing view within a state was to rid the state of coal-fired utilities, the allocation scheme would provide a powerful tool for making coal-fired units prohibitively expensive to run, to the detriment of important national objectives of maintaining fuel diversity. Consequently, the commenter favored a uniform allocation scheme imposed at the national level, based on the heat input criteria expressed by EPA, but determined in a way that does not favor one coal type over another.

Several commenters (OAR-2002-0056-0730, -1682, -2064, -2108, -4139) supported the CAA section 111(d) approach because it would allow more state and local input. Several commenters (OAR-2002-0056-0730, -1682, -2064) submitted states are in the best position to make allocations that protect the environment and address hot spots. One commenter (OAR-2002-0056-2108) preferred to develop its own system for allowance allocation, flow control, banking, and other trading issues. Another commenter (OAR-2002-0056-4139) supported the proposed flexibility to choose what allowance allocation methodology states will use to determine their mercury budgets: auction or free distribution of allowances, permanent or updated allowances, and allowances based on input, output, or emission reductions. The commenter stated that for interstate trade, however, the rule should specify that the trade is allowable only if the section 111(d) limits for existing sources are as stringent or more stringent in the selling state as for the facility in the purchasing state. The commenter believed that while this is more complicated because of the different subcategories, a matrix to represent appropriate exchanges could be developed.

One commenter (OAR-2002-0056-3437) stated that in the NPR and SNPR states are allowed to establish their own allocation methodology. The commenter assumed this would include existing and new sources and any set asides. EPA then requested comment on whether an allocation methodology should be mandated depending on whether a state participates in an interstate trading program, an intrastate trading program, or no trading program. The commenter believed states should have the flexibility in addressing the allocations under the cap irrespective of participation in a particular program.

One commenter (OAR-2002-0056-3552) commented on whether to require the State to allocate allowances to each unit in accordance with the model cap and trade rule. According to the proposal, a state may allocate allowances using its own method. The commenter requested the flexibility not to follow EPA's methodology if the state determines it is not stringent enough to protect the public health. The commenter submitted that many states are limited in their rulemaking authority to be no stricter than federal standards.

One commenter (OAR-2002-0056-2181) noted that while EPA uses a heat input rate adjusted by subcategories by fuel source for determining State budgets, States may choose how they will allocate allowances to each affected Utility Unit. The commenter agreed that States should not be mandated to use the proposed hypothetical allocation method when budgeting to specific units. Among the choices the EPA recognized, States may consider a baseline heat input or baseline power output, updating or permanent allocation, and auction programs. The

commenter believed that while on the one hand, EPA is careful to encourage States to utilize an approach that is best suited for specific State circumstances, on the other, it notes that those who adopt its method can count on a quick approval by the Agency. The commenter submitted this could bias certain States toward adopting the EPA approach without offering thorough consideration of the benefits of alternative allocation strategies. The commenter recommended that EPA eliminate this inherent bias.

Several commenters (OAR-2002-0056-1671, -2064) submitted that the rule should allow states to permanently retire mercury credits. The commenters added that credits should expire by a final compliance date.

One commenter (OAR-2002-0056-2898) suggested that EPA could provide a mechanism for units to petition EPA to provide fair and accurate allocations to existing units. The commenter supported the comments submitted to EPA on this issue by the National Rural Electric Cooperative Association.

One commenter (OAR-2002-0056-2721) noted that EPA is leaving the options to the individual states to determine if the allowances would be permanently issued: 1) year by year, 2) 5-10 year allocations where mercury allowance allocations would be periodically placed into the Mercury allowance Trading system for 5-10 consecutive control periods, or 3) a single permanent allocation where the mercury allowance allocation would be set only once in the beginning of the trading program. The commenter supported the permanent issuance of allowances. The commenter stated this would allow utilities to be better prepared for planning for the future. This planning would allow them to put in-place the appropriate removal technologies without jeopardizing electrical generation and other balance of plant issues. The commenter stated that new units after initial allocation would be required to go to the marketplace to gain allowances under option 3. Under options 1 and 2 the new unit would be allocated allowances only with a corresponding reduction from an existing unit. The commenter submitted that the uncertainty is in what allocation plan each state chooses. The commenter believed that leaving the choice up to the states would weaken the overall trading program and place an unfair financial burden on these facilities, especially for units in a state with few allowances.

Response:

State adoption of the model rule will ensure consistency in certain key operational elements of the program among participating States, while allowing each State flexibility in other important program elements. Uniformity of the key operational elements is necessary to ensure a viable and efficient trading program with low transaction costs and minimum administrative costs for sources, States, and EPA. Consistency in areas such as allowance management, compliance, penalties, banking, emissions monitoring and reporting and accountability are essential.

The EPA's intent in issuing a model rule for the Hg Budget Trading Program is to provide States with a model program that serves as an approvable strategy for achieving the

required reductions. States choosing to participate in the program will be responsible for adopting State regulations to support the Hg Budget Trading Program, and submitting those rules as part of the State Plan. There are two alternatives for a State to use in joining the Hg Budget Trading Program: incorporate 40 CFR part 60, subpart HHHH by reference into the State's regulations or adopt State regulations that mirror 40 CFR part 60, subpart HHHH, but for the potential variations described below.

Some variations and omissions from the model rule are acceptable in a State rule. This approach provides States flexibility while still ensuring the environmental results and administrative feasibility of the program. EPA finalizes that in order for a State Plan to be approved for State participation in the Hg Budget Trading Program, the State rule should not deviate from the model rule except in the area of allowance allocation methodology. Allowances allocation methodology includes any updating system and any methodology for allocating to new units. Additionally, States may incorporate a mechanism for implementing more stringent controls at the State level within their allowance allocation methodology.

State plans incorporating a trading program that is not approved for inclusion in the Hg Budget Trading Program may still be acceptable for purposes of achieving some or all of a State's obligations provided the general criteria. However, only States participating in the Hg Budget Trading Program would be included in EPA's tracking systems for Hg emissions and allowances used to administer the multi-state trading program.

In terms of allocations, States must include an allocation section in their rule, conform to the timing requirements for submission of allocations to EPA that are described in this preamble, and allocate an amount of allowances that does not exceed their State trading program budget. However, States may allocate allowances to budget sources according to whatever methodology they choose. EPA has included an optional allocation methodology but States are free to allocate as they see fit within the bounds specified above, and still receive State Plan approval for purposes of the Hg Budget Trading Program.

5.9.3 State Authority under 111

Comment:

Several commenters (OAR-2002-0056-1692, -1802, -2911, -2915, -3432, -3445, -3454, -3463, -3543, -3556, -4191, -4891) stated a preference for a national trading program. One commenter (OAR-2002-0056-1692) stated that the flexibility inherent in well-designed emission trading programs, such as the Title IV acid rain program, is preferable to the rigidities of unit- or source-specific controls. The commenter believed however, in order to secure the benefits of this flexibility, either of the alternative regulatory vehicles EPA proposed under sections 111(d) or 112(n)(1) must lend itself to a truly national emissions trading program, with certainty in the assignment of emission allowances–essential for planning and executing cost-effective emission control strategies. The commenter stated that the "opt- in" nature of state participation in the 111(d) proposal, which provides too much leeway to individual state SIP determination processes, and the open-ended potential for risk-based assessment of mercury reduction requirements under the 112(n)(1) alternative, jeopardizes the benefits associated with a

well-designed emissions trading regime. (Many commenters expressed concerns with the opt-in nature of state participation in the CAA 111(d) proposal; see comment below in this section.)

One commenter (OAR-2002-0056-3543) stated that a national program is needed to control mercury emissions to help restore Texas water bodies since evidence exists that some significant portion of the mercury originates beyond Texas borders. Several commenters (OAR-2002-0056-2915, -4191) submitted that mercury allowances trading should be allowed to occur throughout the nation to make the cap and trade program as viable as possible. The commenters believe a nation-wide trading market would reduce mercury emissions faster and more cost effectively because there would be increased opportunities and demand for early mercury reductions that could be "banked" for later use. Several commenters (OAR-2002-0056-3432, -3445) stated that EPA must not allow individual states to interfere with an emission trading compliance option. Commenter (OAR-2002-0056-3445) added that in order for a mercury trading program to be successful, a robust marketplace is necessary. The commenter believed that if trading is restricted, the efficiencies of a cap-and-trade system would be lost.

Several commenters (OAR-2002-0056-1673, -2929) submitted that trading should be allowed over the broadest interstate region or largest area possible. One commenter (OAR-2002-0056-2929) stated that this would capitalize on all efficiencies. The commenter believed EPA should make every attempt to promote unfettered emissions trading in the final mercury rule.

One commenter (OAR-2002-0056-2160) submitted that if EPA chooses a cap and trade approach, allowances should be tradable across state boundaries.

One commenter (OAR-2002-0056-2161) stated both the MACT and Cap-and-Trade approaches have attributes and problems. Whichever approach EPA chooses, the commenter felt it would be imperative that EPA continue to recognize in any regulation the inherent problems with controlling mercury for plants burning subbituminous coal. The commenter believed the proposed MACT level of control for subbituminous plants is appropriate; if EPA deemed it necessary to appreciably change this level, the commenter strongly urged EPA to re-propose this regulation. The commenter submitted that if EPA chose a Cap and Trade program, it should be patterned after the highly successful Title IV SO_2 program. The commenter urged EPA to ensure that this program is applied in a consistent manner across the states. Differences in program design or implementation by individual states must be minimized. The commenter agreed that as EPA discussed in their proposal for an NSPS cap and trade program, the Title IV program has demonstrated that it is an effective program and has substantially reduced emissions of acid rain precursors.

Many commenters (OAR-2002-0056-1802, -1859, -2224, -2264, -2422, -2452, -2560, -2835, -2850, -2897, -2911, -2948, -3452, -3463, -3514, -4891) expressed concern that the "opt-in" nature of state participation in the CAA section 111(d) program would provide too much uncertainty associated with individual SIP determination processes. Specific concerns stated by the commenters included the following: states may not participate in a national trading

program; arbitrary confiscation or other limitations on the use of emission allowances; reallocation of emission allowances among non-emitting source sectors, e.g., non-coal fired EGUs; patchwork of programs varying from state to state; states promoting premature emission allowance retirement; time required for review and approval of separate SIP by state approval authorities, including the necessary notice and public hearings, followed by the necessary review by the EPA will likely extend to a number of years; and a fragmented trading system would not allow sufficient trading to be economical for smaller facilities. The commenters felt that for trading programs to be efficient, equitable, and effective, they must by uniformly applied over broad geographic regions.

Several commenters (OAR-2002-0056-2251, -2332, -2560, -2818, -2835, -2862, -2915, -2948, -3431, -3469, -3514, -4191) believed that state participation in a mercury cap-and-trade program should be mandatory or that states should be prohibited from interfering with the cap-and-trade program. One commenter (OAR-2002-0056-3431) stated EPA should require participation by all states in a mercury cap-and-trade program to create a robust and efficient market system. The commenter stated that a national cap-and-trade program offers the most certainty, flexibility and cost effectiveness for the industry as a whole. According to the commenter, past experience with the Acid Rain program demonstrated that for a cap-and-trade program to be successful, it must have broad-based participation by the states. The commenter stated that even the NO_x Budget Rule in the Northeast, which allowed for some state variation from a model rule, was slow to develop into a robust market with readily available interstate trades. According to the commenter, only when is there a robust market is the development of cost effective control technologies incentivized. The commenter believed if states are given the option not to participate in a cap and trade program or to create significant variation in their rule pursuant to a CAA §111 SIP approach, the overall target mercury reduction may not be achieved and non-participating states would disadvantage generation in their state by increasing generation costs and reducing system reliability. One other commenter (OAR-2002-0056-2560) cited success of the Title IV Acid Rain SO_2 program being attributed to mandatory participation. One commenter (OAR-2002-0056-3514) stated they would only support regulation under CAA section 111 if states are required to fully participate in the section 111 interstate cap-and-trade program.

One commenter (OAR-2002-0056-2862) believed a federal mercury emission program would be most appropriate for an emission that is national and global in scope. The commenter submitted that if EPA decides to proceed to regulate mercury under a section 111 Cap and Trade alternative, states must be required to participate in the interstate cap-and-trade program. With this alternative, the federal performance standard would be implemented as a state-specific emissions cap.

One commenter (OAR-2002-0056-2948) stated that in order for the trading program to be successful, EPA would need to prohibit states from interfering with any mercury cap-and-trade program. The commenter added that although states are permitted under the Act to impose more stringent emissions limitations on sources within their borders, states must be expressly prohibited from restricting the ability of sources to sell or trade mercury allowances. The commenter also stated that similarly, EPA needs to prohibit states from interfering with the

EPA-established cap on mercury emissions. According to the commenter, in the final rule, EPA needs to make clear that states cannot require sources within their borders to surrender more allowances than federally required and cannot place restrictions on the sale of mercury allowances by sources within their borders. Another commenter (OAR-2002-0056-2835) recommended that EPA reduce the opportunity for widely diverging state plans by prescribing the manner in which states allocate allowances to sources participating in the trading program. Similarly, several commenters (OAR-2002-0056-2252, -2332) stated that a mercury trade program that is state run will lead to state-to-state differences in implementation. These commenters asserted that it is not clear that this method is consistent with the goal of allowances that are "readily transferable between all regulated utilities" (69 FR 4652 Summary dated, January 30, 2004). One commenter (OAR-2002-0056-2818) suggested that, if EPA determines that a cap and trade program is the best way to reduce mercury emissions, then EPA should administer the program so it is available to all utility units.

Several commenters (OAR-2002-0056-2862, -2948) disagreed with the amount of flexibility states will have under the CAA section 111 cap-and-trade program. One commenter (OAR-2002-0056-2862) noted that EPA's section 111 cap-and-trade proposal would allow states the flexibility to determine how to allocate the capped mercury allowances to in-state sources. State implementation plans must, however, allocate the full emissions cap, and all of the EPA-issued allowances must be issued to in-state sources. The commenter submits that because the state cap is essentially the CAA section 111 performance standard, states choosing not to allocate all of their allowances would essentially be "opting out" of the section 111 program, and modifying the underlying federal standard of performance. The Clean Air Act does not permit this.

The second commenter (OAR-2002-0056-2948) disagreed with EPA's proposal to allow states to opt out of a CAA section 111 trading program. According to the commenter, because promulgation of a section 111 trading program would necessitate a determination by EPA that the program is the "best system" for reducing mercury emissions from coal-fired power plants, states cannot interfere with that determination. The commenter believed that although states do have some authority under section 111, they lack authority to change the standard of performance set by EPA. According to the commenter, if EPA permits states to opt out of a section 111 trading program, this will in essence allow states to change the standard of performance, which the CAA does not authorize. The commenter added that similarly, states cannot issue only a portion of the allowances available within the state because this would also permit that state to modify the federally determined standard of performance.

Several commenters (OAR-2002-0056-0598, -3449, -3543) believed states should be allowed to opt out of the CAA section 111 cap-and-trade program. One commenter (OAR-2002-0056-3449) submitted that states should have authority not to participate in emission trading programs and to require emission reductions beyond those specified in state budgets.

One commenter (OAR-2002-0056-2721) believed that States should be required to participate in the inter-State trading program. The commenter submitted that in instances where

there are few or only one utility in a State (i.e., South Dakota), the utility would be at an extreme economic disadvantage relative to a utility in a neighboring state that has multiple affected units when allowing each state to determine independently the amount of new source set aside or allocations of allowances to other industry sources.

One commenter (OAR-2002-0056-2922) stated that EPA must make clear that states cannot interfere with the cap-and-trade program. The commenter offered as example, states should be expressly prohibited from requiring units to surrender more allowances than required by EPA's one-allowance-per-ounce rule or from placing restrictions on the intrastate or interstate transfer of allowances. The commenter urged EPA to include provisions in its rules that expressly prohibit states from interfering with the cap-and-trade program in the ways described above or in any other way.

One commenter (OAR-2002-0056-2224) had concerns about potential adverse impacts that might occur through an inflexible, unit-specific regulatory control program. Specifically, the commenter was concerned that the benefits and flexibility of a market-based program could be entirely lost if it were determined that a national cap-and-trade program is not legally authorized or, if states declined to implement the cap-and-trade option under section 111 alternative. According to the commenter, to anticipate these concerns, EPA should allow states to establish flexible procedures for implementing the mercury reduction requirements under the "section 111" option. The commenter stated that in addition to the cap-and-trade program proposed in the supplement notice, these procedures should allow states to implement the reductions through emissions averaging or trading on at least a facility-wide basis. The commenter noted that one alternate control program, which was specifically provided for in the nationwide MACT alternative, would be the emissions averaging program modeled after the NO_x acid rain program. The commenter asserted that the rule should clarify that this provision should also specifically be provided for under the section 111 implementation approach for states that may elect not to participate in the nationwide cap-and-trade program. Another alternative that the commenter strongly urged EPA to adopt was a state-wide, mass emissions (i.e., ounces/year) approach that would involve mass emissions caps set for each facility (calculated based on the rule's emission rates). The commenter asserted that providing at least this much flexibility would be essential to enable electric generators to develop least-cost strategies for controlling mercury. According to the commenter, among other things, it would provide significant additional compliance flexibility for multi-unit stations while meeting the overall reduction goals of the program. The commenter stated that section 111(d) provides states with broad latitude in designing the mercury control program, and emissions averaging would thus be an appropriate implementation mechanism that should be available to states so long as the state program achieves the mercury reductions required under the final EPA rule.

Response:

As discussed in the final preamble, each State must impose control requirements that the State demonstrates will limit Statewide emissions from affected new and existing sources to the amount of the budget. Consistent with CAIR, EPA is finalizing that States may meet their Statewide emission budget by allowing their sources to participate in a national cap-and-trade

program. That is, a State may authorize its affected sources to buy and sell allowances out of State, so that any difference between the State's budget and the total amount of Statewide emissions will be offset in another State (or States). Regardless of State participation in the national cap-and-trade program, EPA believes that the best way to assure this emission limitation is for the State to assign to each affected source, new and existing, an amount of allowances that sum to the State budget. Therefore, EPA is finalizing that all regulatory requirements be in the form of a maximum level of emissions (i.e., a cap) for the sources.

As proposed in the SNPR, EPA is finalizing that each State must submit a demonstration that it will meet its assigned Statewide emission budget, but that regardless of whether the State participates in a trading program, the State may allocate its allowances by its own methodology rather than following the method used by EPA to derive the state emissions budgets. This alternative approach is consistent with the approach in the CAIR.

States remain authorized to require emissions reductions beyond those required by the State budget, and nothing in today's final rule will preclude the States from requiring such stricter controls and still being eligible to participate in the Hg Budget Trading Program.

Comment:

Several commenters (OAR-2002-0056-1611, -3909) stated that the proposed rules should not override more stringent State requirements. One commenter (OAR-2002-0056-2835) stated that States are always free to adopt mercury control requirements more stringent than the federal requirements to address any adverse local impacts from EGU emissions.

One commenter (OAR-2002-0056-3199) asked EPA to consider provisions that would allow states to control individual plants in the event there is a demonstrated mercury hot spot. Similarly, another commenter (OAR-2002-0056-2909) stated that EPA rules must provide the explicit right and authority for States to deal with residual local issues.

Response:

Moreover, States remain authorized to require emissions reductions beyond those required by the State budget, and nothing in today's final rule will preclude the States from requiring such stricter controls and still being eligible to participate in the Hg Budget Trading Program.

Comment:

One commenter (OAR-2002-0056-2430) stated that EPA must clearly define its role in overseeing a cap-and-trade program if a state elects to participate. The commenter submitted that States are unable to evaluate the cost associated with implementation of the rule without clearly stated commitments.

Response:

States may elect to participate in an EPA-managed cap-and-trade program for coal-fired Utility Units greater than 25 MW. To participate, a State must adopt the model cap-and-trade rules finalized in this section of today's rule with flexibility to modify sections regarding source Hg allocations. For States that elect not to participate in an EPA-managed cap-and-trade program, their respective State Hg budgets will serve as a firm cap.

In a system run by EPA, source information management, emissions data reporting, and allowance trading is done through on-line systems similar to those currently used for the Acid Rain SO_2 and NO_x SIP Call programs

Comment:

Several commenters (OAR-2002-0056-2264, -2422) claimed that CAA section 111(d) cap-and-trade program would place an unfair burden on many States that are already required to develop and approve controversial ozone and $PM_{2.5}$ SIPs. Moreover, the inclusion of mercury emission programs within often time consuming State SIP submission and approval processes would effectively reduce the time available for source compliance planning and control strategy implementation. In this regard, the commenters noted that the proposed section 111(d) SIP-based trading program has been rejected in principle by 11 of the 12 northeastern states of the Ozone Transport Commission (OTC). Eleven of the 12 OTC states voted to oppose any cap-and-trade program for mercury, with Virginia abstaining. The commenters pointed out that other states have voiced similar concerns about emissions trading for mercury. The commenters believed these developments underscore the potential difficulties associated with an emission trading plan implemented through section 111(d).

Response:

EPA is committed to assist states in the implementation of the program. States may elect to participate in an EPA-managed cap-and-trade program for coal-fired Utility Units greater than 25 MW. To participate, a State must adopt the model cap-and-trade rules finalized in this section of today's rule with flexibility to modify sections regarding source Hg allocations. For States that elect not to participate in an EPA-managed cap-and-trade program, their respective State Hg budgets will serve as a firm cap.

In a system run by EPA, source information management, emissions data reporting, and allowance trading is done through on-line systems similar to those currently used for the Acid Rain SO_2 and NO_x SIP Call programs.

5.9.4 State Resources

Comment:

Several commenters (OAR-2002-0056-2120, -2219, -2247, -2430, -2871, -2887, -2889, -2897) stated that the cap-and-trade program under CAA section 111 would place an additional burden on states. One commenter submitted that section 111(d) would place an unfair burden on many States that are already required to develop and approve controversial ozone and $PM_{2.5}$ SIPs.

Several commenters (OAR-2002-0056-2120, -2430) asserted noted that the cap-and-trade program proposed in the supplemental rule would appear to require significant resources for state and local agencies, the source of which is not accounted for in EPA's proposal. The commenters state the same is true for the enforcement and compliance scheme. The commenters believed that adding additional burden to overextended states is a recipe for failure.

One commenter (OAR-2002-0056-2219) stated that because of the additional burden of the budget permitting system it is likely that the permitting time line would be delayed and create unacceptable delays in emission reductions. One commenter added that the resources needed to implement a cap and trade program under section 111 would be much higher than the resources needed for MACT standards because the state must conduct a rulemaking to obtain authority to administer section 111(d) emission guidelines and they currently have no trading system that could be used as a model to allocate credits. The commenter also questioned EPA's concerns about states being overwhelmed by requests for Title V permit modifications for 1 year compliance extensions under a MACT standard. The commenter stated that amending permits to extend a compliance date would be far less resource intensive than implementing and administering the allowance distribution process in the mercury trading program.

Response:

States may elect to participate in an EPA-managed cap-and-trade program for coal-fired Utility Units greater than 25 MW. To participate, a State must adopt the model cap-and-trade rules finalized in this section of today's rule with flexibility to modify sections regarding source Hg allocations. For States that elect not to participate in an EPA-managed cap-and-trade program, their respective State Hg budgets will serve as a firm cap.

In a system run by EPA, source information management, emissions data reporting, and allowance trading is done through on-line systems similar to those currently used for the Acid Rain SO_2 and NO_x SIP Call programs.

Comment:

One commenter (OAR-2002-0056-1596) stated that enforcement personnel have little training about how to determine compliance with a cap-and-trade program. The commenter believed that this approach would allow companies to hide pollution with numbers that are hard to verify.

Response:

As discussed in the final preamble, EPA will jointly administer the cap-and-trade program with States. EPA is requiring monitoring under Part 75 and EPA is running the system to collect emissions data and track allowances.

Comment:

One commenter (OAR-2002-0056-3448) asserted that EPA's lack of an effective national strategy has driven states to do their own rules. The commenter submitted that Massachusetts, Connecticut, New Jersey, and Wisconsin have either legislation or rules and others are sure to follow. The commenter believed states should not have to expend resources on a problem that is best addressed on a nationwide basis. The commenter stated that EPA has created this situation.

Response:

Under the final rule EPA is establishing a national program to reduce Hg emissions by allowing states to participate in a cap-and-trade program.

Comment:

One commenter (OAR-2002-0056-2883) believed that the EPA should hold regional workshops to assist municipal and state-owned utility generation facilities with compliance with these final rules to reduce mercury and nickel.

Response:

EPA is committed to assist states in the implementation of the program.

RESPONSE TO SIGNIFICANT PUBLIC COMMENTS ON THE PROPOSED CLEAN AIR MERCURY RULE

Received in response to:

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 4652; January 30, 2004)

Supplemental Notice for the Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 12398; March 16, 2004)

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources, Electric Utility Steam Generating Units: Notice of Data Availability
(69 FR 69864; December 1, 2004)

Docket Number OAR-2002-0056

6.0 MERCURY EMISSIONS MONITORING

US Environmental Protection Agency
Emissions Standards Division
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

15 March 2005

General Outline

6.0 MERCURY EMISSIONS MONITORING

6.1 SELECTION OF MONITORING METHOD

Comment:

Several commenters (OAR-2002-0056-2429, -2634, -2718, -2922, -3565) noted that in the proposed MACT in subpart UUUUU, EPA's proposed 40 CFR part 75 revisions include provisions for use of both Hg CEMS and a sorbent trap monitoring system meeting Method 324. However, EPA also proposes to prohibit new units that commence commercial operation more than 6 months after publication of the final rule from using Method 324. The commenters do not believe that either of EPA's proposed alternatives to restrict use of Method 324 is appropriate or justified.

Response:

EPA agrees with the commenters. In light of comparative field data, EPA believes that monitoring using sorbent media should be as similar as possible to monitoring using Hg CEMS. Therefore, today's final rule allows the sorbent trap methodology to be used for new units.

Comment:

One commenter (OAR-2002-0056-2375) stated that if the EPA promulgates a requirement that all sources above a certain emissions threshold monitor with CEMS, the commenter recommended that the threshold be 76 lb/year.

Response:

EPA's rule will require continuous monitoring (Hg CEMS or sorbent trap monitoring systems) for all units with annual Hg mass emissions greater than 29 lb/yr. For units with Hg emissions of less than or equal to 29 lb/yr, a low mass emitter option is provided that is less rigorous but still environmentally conservative.

Comment:

Numerous commenters (OAR-2002-0056-1596, -2101, -2429, -2485, -2634, -2718, -2827, -2850, -2861, -2918, -2922, -2932, -2948, -3406, -3432, -3455, -3536, -3539, -3565) expressed concern that EPA's proposal is unfairly and unjustifiably biased against the sorbent trap method. The commenters did not support Alternative #1, because it restricts the use of sorbent traps to low emitting units. Commenters were generally more receptive to Alternative #2, except for the proposed quality assurance/quality control (QA/QC) procedures for sorbent trap systems (most notably the quarterly relative accuracy testing), which they found to be inappropriate, overly burdensome, costly, and time-consuming. Several commenters stated that

EPA has no justification for restricting the use of the sorbent trap method because it has been shown during EPA-sponsored mercury (Hg) monitoring demonstrations that the method can achieve accuracies comparable, and in some cases better than those achieved by Hg CEMS. Other commenters recommended that the type of QA/QC procedures prescribed for sorbent trap systems should be more specific to the sorbent trap technology and should be more clearly defined. Finally, a number of commenters objected to the proposal to report the higher of the two Hg concentrations from the paired sorbent traps, and recommended that the results be averaged instead.

Response:

Section 75.81(a) of the final rule adopts a modified version of Alternative #2, which allows the use of sorbent trap systems for any affected unit, provided that rigorous, technology-specific QA procedures are implemented. The operational and QA/QC procedures for sorbent trap systems are found in section 75.15 and in appendices B and K of the final rule. EPA also has incorporated the recommendation of the commenters to use the average of the Hg concentrations measured by the paired sorbent traps meeting specified criteria. And in cases where one of the traps is accidentally lost, damaged or broken, the owner or operator would be permitted to report the results of the analysis of the other trap, if valid.

Recent field test data from several different test sites indicate that sorbent trap systems can be as accurate as Hg CEMS. Recent field tests have answered questions regarding which substances in the flue gas can interfere with accurate vapor phase Hg monitoring by sorbent traps. Sorbent trap technology also has evolved, with the addition of a third section that enables the traps to be subject to enhanced QA procedures. And the Agency has been working with industry and equipment manufacturer representatives to develop new QA procedures that are more relevant to the operation of a sorbent trap system. These improved QA procedures are included in the final rule. In view of this, EPA believes that it is appropriate to extend the use of sorbent trap systems to all affected units.

EPA notes that although the restrictions on the use of sorbent traps have been removed, there are some inherent risks associated with the use of this technology. For instance, because sorbent traps may contain several days of accumulated Hg mass, the potential exists for long missing data periods, if the traps should be broken, compromised, or lost during transit or relative accuracy test audit (RATA) of a sorbent trap system is performed, the results of the test cannot be known until the contents of the traps have been analyzed. If the results of the analysis are unsatisfactory, the RATA may have to be repeated. This also may resulting in a long missing data period. However, EPA believes that these undesirable outcomes can be minimized by following the proper handling, chain of custody, and laboratory certification procedures in the final rule. The use of redundant backup monitoring systems can also help to reduce the amount of missing data substitution.

Comment:

One commenter (OAR-2002-0056-4891) stated that any monitoring method that meets the EPA criteria should be allowed. As noted above, accurate Hg monitoring technologies, including accurate continuous emissions monitoring systems for Hg, are not yet commercially available. When such equipment will be successfully tested and commercially available is not known. To facilitate the use of new Hg monitoring technologies as they are developed, the commenter urges EPA to allow power plant owner/operators subject to the Utility Mercury Reduction Rule (UMRR; now known as the Clean Air Mercury Rule, CAMR) to use any monitoring method that meets EPA's standard criteria for reliability and accuracy. Unduly limiting the options available for monitoring emissions would only serve to drive up the cost of what is already an extremely expensive regulatory scheme. Given the current lack of accurate Hg emissions monitoring methods, it will be important for facilities to have the flexibility to use monitoring methods that are developed in the future as a result of the adoption of UMRR.

Response:

EPA agrees with the commenter and has specified a performance-based approach for monitoring criteria. The performance-based approach allows for use of various suitable sampling and analytical technologies while maintaining a specified and documented level of data quality.

6.2 MISSING DATA PROCEDURES

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2861, -2922, -3565) were concerned that EPA had overlooked a potential problem with the requirement to subject Hg CEMS and Method 324 to periodic RATAs and/or other audits that rely on comparison to EPA test methods for Hg (including Method 29 and the Ontario-Hydro method). Unlike the instrumental reference methods routinely used to QA SO_2 and NO_x CEMS, the available Hg test methods can take days to complete and weeks for the return of test results from the laboratory. Under the current general provisions, a monitor that fails a RATA would be deemed out-of-control beginning with the hour that the required test was conducted until the hour that the test is successfully passed. This construct could lead to significant implementation problems with respect to missing data and requirements to calculate and report data. If a source does not know until weeks after a RATA is completed whether the test was passed, the source has no means of minimizing missing data associated with a failed test. Similarly, once it is clear that a test has been failed, the source must schedule and perform a new test and wait for results before determining whether the monitor is back in control and the data are valid. Under these procedures, monitoring systems that fail a RATA will have significant amounts of missing data due simply to the delay in obtaining testing results. Until a method is developed that will allow for onsite results of Hg RATA testing, EPA must provide special rules to avoid these unavoidable implementation problems.

Response:

EPA Agrees with the commenters. Based on field testing., EPA intends to develop adequate criteria for a performance based instrumental reference method for Hg. Initial evaluations of such a method have already begun.

Comment:

Several commenters (OAR-2002-0056-2922, -2634, -2718) stated that section 63.10020(c) states that any period for which a monitoring system is out of control and data are not available constitutes a "deviation." The commenters object to labeling each period when a monitor fails a QA/QC test and is therefore "out-of-control" as a "deviation" of the requirement to monitor. Monitoring systems no matter how well maintained will occasionally fail a QA/QC test. As long as the source takes appropriate action, no deviation from the requirement to monitor has occurred. The commenters are especially concerned about this provision given the uncertainty surrounding the ability of the Hg CEMS to satisfy the proposed standards in PS-12A on an ongoing basis.

Response:

EPA has decided to control Hg emissions using a cap-and-trade approach rather than by using maximum achievable control technology (MACT, 40 CFR part 63).

Comment:

Several commenters (OAR-2002-0056-1854, -2634, -2718, -2721, -2891, -2922, -3403, -3455, -3565, -2855) stated that the proposed missing data procedures seem to be unduly harsh and appear to be unfairly biased against the use of the sorbent trap method. The commenters indicated that the missing data routines should properly consider the uncertainties associated with Hg monitoring, i.e., there is a lack of evidence that high percent monitor data availability (PMA) is achievable with these monitoring systems. Other commenters suggested that EPA should remove the maximum potential concentration (MPC) provision altogether for Hg monitors and fill in all missing data periods using average concentrations until more confidence is gained in the reliability of Hg monitors.

Response:

The final rule retains the basic missing data substitution approach for Hg that was proposed. This approach has worked well in the Acid Rain and NO_x Budget Programs. The conservative nature of the missing data routines has provided a strong incentive to sources to keep their monitoring systems operating and well-maintained. However, the PMA cut points in the final rule have been loosened slightly to account for the present lack of long-term Hg monitoring experience in the U.S. EPA will continue to collect and analyze CEMS and sorbent trap data from various field demonstration projects and will evaluate the performance of

certified Hg CEMS operating on similar source categories (e.g., waste combustors). If the data indicates that the PMA cut points should be changed for Hg CEMS or sorbent traps, the Agency will initiate a rulemaking for that purpose.

The suggestion to remove the MPC provisions and to fill in all missing data periods using average concentrations until EPA develops better procedures was not incorporated in the final rule for two reasons. First, when add-on emission controls that reduce Hg emissions either malfunction and are taken off-line, uncontrolled Hg emissions will result. If the Hg CEMS or sorbent trap system is out-of-control during the control device outage, an appropriate substitute data value must be used to represent uncontrolled Hg emissions and provide an incentive to fix the Hg monitoring system. The MPC concept has successfully been used in the Acid Rain and NO_x Budget Programs.

Second, EPA does not agree with the commenters that using the MPC for certain missing data periods is always unduly harsh or punitive. For the initial Hg MPC determination, the March 16, 2004 SNPR provided three options: (1) use a coal-specific default value; or (2) perform site-specific emission testing upstream of any control device; or (3) base the MPC on 720 hours or more of historical CEMS data on uncontrolled Hg emissions. The Agency believes that these options provide adequate opportunity for affected units to develop appropriate MPC values.

Regarding the missing data routines for sorbent trap systems, available field test data have indicated that these systems are capable of performance that is equivalent to a CEMS. In view of this, EPA believes that sorbent traps should be treated on a a more equal footing with Hg CEMS in many areas, including the missing data provisions.

Finally, EPA notes that a new missing data policy has been posted on the Clean Air Markets Division web site. The policy allows the four-tiered missing data algorithms to be applied hour-by-hour, in a stepwise manner, based on the PMA. Previously, the Agency's policy had been to determine the PMA at the end of the missing data period and to apply a single substitute data value (sometimes the MPC, if the ending PMA was < 80 percent) to each hour in the missing data block. This new, more lenient interpretation of the 40 CFR part 75 missing data requirements will result in more representative missing data substitution and minimize the use of the MPC.

Comment:

One commenter (OAR-2002-0056-3455) stated that, in reference to Appendix A to the Preamble--Proposed Changes to Parts 72 and 75, (Proposed Rules March 16, 2004); page 12418, the section dealing with missing data seems to be either incorrect or unduly harsh; in either case, the section requires clarification. The procedure states that missing data starts when the traps that first caused the problem were put into service, but it further states that this missing data period ends only when the next valid Hg concentration data are first obtained. Because the data is not "obtained" until the traps have been analyzed and the reports sent back to the owner, this

would mean that the missing period data would not only include time that the failed traps were in service, it would also include the time period that the next valid set of traps were in service.

Response:

The wording in the final rule has been clarified to say that the missing data period would end on the commencement of operation of another pair of sorbent traps that contain valid Hg concentration data.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2922) stated that the proposed Method 324 needs to include provisions for data availability and missing data. Because it is not reasonable for EPA to expect 100 percent data capture from any method, EPA must specify at what point sorbent trap data would need to be filled in and what method would be used. EPA might also consider providing alternative minimum data collection and missing data requirements that would to apply simply to Hg data, regardless of the method of collection.

Response:

See the Missing Data discussion in the preamble.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2922) stated that EPA needs to clarify how periods of startup, shutdown, and malfunction are to be treated in data collection and reporting. The proposed rule appropriately states that deviations that occur during periods of "startup, shutdown, or malfunction" ("SSM") are "not violations" if the source was operating in accordance with its SSM plan. However, the proposal does not explain whether or how those data would be excluded from the compliance calculation, or how they would be treated with respect to the data collection requirements. Presumably EPA does not mean that any 12-month rolling average in excess of the standard that includes a period covered by an SSM plan is not a violation. On the other hand, data collected during periods of SSM are not representative of normal operations and should not be included in data averages used to determine compliance and missing data substitution procedures. EPA needs to give additional thought to these issues and provide clear instructions in the rule for how such periods would be treated.

Response:

These comments pertain to the January 30, 2004 NPR, in which both a MACT rule and a NSPS rule were proposed for Hg. The proposed MACT approach has not been selected for promulgation. The NSPS has been finalized as a series of amendments to 40 CFR part 60, subpart Da. The NSPS clearly states that data recorded during periods of unit startup, shutdown, and malfunction are not included in the calculation of the 12-month rolling average

Hg emission rate. However, the owner or operator is required to report the number of hours excluded from the calculations for those reasons.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2922) stated that EPA proposes to require sources that utilize a FGD system to maintain records of scrubber operating parameters for each Hg missing data period in order to show proper operation of the scrubber. Because recording of FGD parameters generally is not automated, this requirement could become very burdensome if there is a significant amount of missing data. As a result, the commenters request that EPA consider allowing sources the option of utilizing parameters other than control device operating parameters, such as documented compliance with an SO_2 permit limit using the SO_2 CEMS, to establish proper operation of the FGD during Hg missing data periods.

Response:

The final rule allows quality assured SO_2 data to be used to demonstrate proper operation of an FGD.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2922) stated that proposed data collection and missing data scheme under section 63.10008(d)(4) has several significant flaws. The first flaw is the assumption that these minimum criteria are reasonable requirements for Hg CEMS. There are no data to support the assumption that Hg CEMS will be capable of operating within the specified performance criteria for 18 hours a day for 21 days each month. Sources should not be penalized for failing to meet minimum criteria that may not in fact be achievable. As a result, EPA will need to continue to review this requirement in light of additional data collected between now and the first compliance deadline. EPA also should revise the rules to allow use of Method 324 as a backup for any source that chooses that option, and should allow data from that method to be used to meet the minimum data requirements in lieu of a Hg CEMS. The second flaw in the rule, even if you assume that the Hg CEMS can meet the minimum criteria, is the failure of the rule to distinguish between unit operating hours and non-operating hours in determining if a day is complete. If the minimum requirement applies regardless of unit operation, sources will be required to try to keep monitors running and quality assured, and to calculate mass Hg, even if the unit is not operating in order to collect enough data for a complete day. That is contrary to section 63.10020(a) ("you must monitor continuously at all times that the affected source is operating"). That would also result in months with little operation, and therefore very little actual Hg mass emissions data, being counted in the 12-month rolling average with the same weight as months with significant operation. If, on the other hand, the source does not collect that data, any day the unit does not operate and most days involving a startup or shutdown are likely to be "incomplete" and not count towards the required 21 days for a complete month. Under the missing data provisions, that approach would mean that valid data would be thrown out simply because there was not enough unit operation in the month. Sources

should not be required to operate monitors when they are not operating, and should not be penalized for non-operation. As a result, EPA should give more thought to whether the data collection and missing data provisions associated with the calculation of "monthly" averages is the best approach.

Response:

The proposed MACT rule has not been selected for promulgation. However, the proposed NSPS rule for Hg, which contained the same data capture requirements as the MACT rule, has been finalized. In the final rule, the minimum data capture requirement for the Hg monitoring systems is 75 percent of the unit operating hours in each month. If this requirement is not met for a particular month, a substitute Hg emission rate must be reported. Compliance with the NSPS emission limit for Hg is determined on a 12-month rolling average basis. The rolling average is weighted according to the number of valid hours of Hg data collected in each month, except when the 75 percent data capture requirement is not met. When that occurs, the substitute Hg emission rate for that month is weighted according to the number of unit operating hours in the month. Months with zero unit operating hours are not included in the rolling average calculations.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2922) stated that EPA proposes to revise 40 CFR 75.20(d) to include Hg CEMS in the list of non-redundant backup monitoring systems that can be used for up to 720 operating hours without a RATA. The commenters request that EPA revise this section, and other sections regarding use of backup monitoring systems and missing data, including 40 CFR 75.80(f), to allow use of sorbent trap monitoring systems as a backup to Hg CEMS and vice versa. The EPA should also allow use of additional paired traps as a backup to a sorbent trap monitoring system.

Response:

The final rule does not prohibit you from using sorbent traps as redundant backup monitors.

6.3 SORBENT TRAP OPERATION AND QA/QC

In view of the many comments received regarding a large number of testing and QA provisions in proposed Method 324, EPA has decided to revise and rename proposed Method 324 as Appendix K to Part 75 in the final rule. Based on comments received and experience gained from field tests since proposal, Appendix K retains certain provisions and revises others in proposed Method 324 to include detailed, performance-based QA standards and procedures for sorbent trap monitoring systems.

Comment:

One commenter (OAR-2002-0056-3455) stated that, in reference to section 75.15(a)-(e), Page 12417, conducting proportional sampling with a Method 324 sampling train may be conducted at a single point. If the velocity profile changes with load, as may sometimes be the case, proportional sampling by determining the velocity at a single point may misrepresent the total gas flow in the stack.

Response:

40 CFR part 75, Appendix K, requires that the output from a part 75 certified stack gas flow monitor be used to maintain a proportional sample flow rate through a sorbent trap or cartridge. All affected sources under the final rule must already comply with the 40 CFR part 75 Acid Rain Program monitoring requirements which include maintaining and quality assuring a stack gas flow monitor. A part 75 certified flow monitor must pass a two-load RATA annually and a three-load RATA every 5 years, and is, therefore, representative of the stack gas flow rate across different loads.

Comment:

One commenter (OAR-2002-0056-3455) stated that, in reference to Method 324 (40 CFR part 63), does not meet EPA's definition of a CEMS (page 12453, section 72.2 Definitions).

Response:

It is true that in section 72.2, a sorbent trap monitoring system is not included in the definition of a CEMS, but rather is defined separately as an "excepted" monitoring system. However, EPA believes that this distinction is more semantic than substantive, since a sorbent trap system samples the stack effluent continuously, and data from the system are combined with hourly readings from a certified 40 CFR part 75 flow monitor to give a continuous record of Hg mass emissions. Relative accuracy test data have shown that a sorbent trap system can measure Hg concentration as accurately as a CEMS.

Comment:

One commenter (OAR-2002-0056-2867) notes that EPA also stated, for the purposes of applying Method 324, "an intermediate sampling rate of 0.3 to 0.5 L/min through each sorbent trap would be used when the unit is operating at the normal load level, whether low, mid, or high. The sampling rate would then be increased or decreased, as appropriate, by 0.1 L/min when the unit operates at the other two load levels" (69 FR 12417). The commenter believed that this sample rate adjustment procedure is not appropriate. The proportional sampling is not necessary, and requiring a step change to the sample rate adds further complication without any appreciable benefit. According to the commenter, a mathematical analysis of the difference between constant flow sampling and proportional flow sampling shows a negligible difference

between the two, with a percent difference of 1.45. The commenter submitted an attachment with the simulated data (based on a realistic scenario). The commenter stated that since the method allows for a ±25 percent change in proportional flow sampling as mentioned above in (69 FR 4736), the percent difference between constant flow sampling and proportional flow sampling is negligible at 1.45 percent, and well within the ±25 percent range. The commenter recommended that proportional sampling not be required because of the added complications in the design of the sampling process, and without the appreciable increase in the accuracy of the measurements. In the undesirable alternative that the EPA requires proportional flow sampling, the commenter recommended the sampling should be done on a continuous proportional basis and not on a 3-step proportional basis. The commenter submited further explanation of the reasons proportional flow sampling is unnecessary as follows. Since Method 324 measures the concentration of the Hg in the stack, it is independent of the flow rate. The procedure included in the rule to calculate the total mass of the mercury emissions includes the stack flow rate as follows: "(3) If you use Method 324 (40 CFR part 63, appendix A), determine the 12-month rolling average mercury emission rate according to the applicable procedures in paragraphs (d)(3)(i) through (v) of this section. (i) Sum the mercury concentrations for the emission rate period, (µg/dscm). (ii) Calculate the total volumetric flow for the emission rate period, (dscm). (iii) Multiply the total mercury concentration times the total volumetric flow to obtain the total mass of mercury for the emission rate period in micrograms. (iv) Calculate the mercury emission rate for an input based limit (lb/Tbtu) using Equation 4 of this section. (v) Calculate the mercury emissions rate for an output-based limit (lb/MWh) using Equation 5 of this section," (69 FR 4724). The commenter pointed out that since any changes in stack flow rate will be taken into account in this calculation, proportional sampling is unnecessary. The commenter asks EPA to clarify their intent on requiring proportional flow for sampling periods greater than 12 hours. The commenter contends that this is not a necessary requirement for accurate measurement of the Hg emissions.

Response:

When stack gas flow changes, Hg concentration may also change. Therefore, the final rule requires flow proportional sampling to better ensure a representative sample. The 3-step adjustment procedure in the proposed rule has not been finalized. Rather, the ratio of the stack flow rate to sample flow rate must be kept constant (± 25 percent) from hour-to-hour.

Comment:

One commenter (OAR-2002-0056-2063) stated that, in reference to the Preamble--Proposed Changes to Parts 72 and 75, (Proposed Rules March 16, 2004), Method 324, since Method 324 is a Reference Method and the main vulnerability on an ongoing basis is the sample volume measurement, quarterly volume measurement calibrations should be required, rather than additional Reference Method (RAA) testing.

Response:

The final rule does not require quarterly RAAs, but has instituted quarterly calibration checks of dry gas meters, and sample-specific volume QA/QC.

Comment:

One commenter (OAR-2002-0056-0544) suggested that should sorbent tubes be utilized for monitoring purposes, the sorbent media should not be restricted to iodated-activated carbon only. There is a sorbent media used to test for Hg vapor in ambient air method listed as NOSH 6009 used in industrial hygiene. These sorbent tubes are readily available from SKC Inc, manufacturer, located in Pennsylvania, part number 226-17-1A. These tubes have been used by many Industrial Hygienists for many years and are time proven for their reliability.

One commenter (OAR-2002-0056-2867) asserted that EPA should publish the QA/QC for the digestion procedure in this rule and disclose the entity that has developed the analytical procedure and written Method 324. The commenter believed this will increase the understanding of the intent in requiring this sampling method and analytical procedure. The commenter stated the current digestion method appears to be biased towards the use of one vendor's procedure. The commenter feels this may give them an unfair market advantage in supplying the traps to the industry. The commenter believed alternate analytical procedures should be allowed, so that one company does not control the market.

Response:

The sorbent media monitoring requirements (formerly Method 324) have been revised to make them performance based, thus providing significant additional flexibility in choice of sampling and analytical approaches, as well as performance criteria used to assess the quality and validity of the monitoring data generated. There are numerous potential approaches for sample preparation, depending upon the analytical technique selected. The performance based approach intentionally avoids specifying that level of detail.

Comment:

One commenter (OAR-2002-0056-3546) stated that they had recently conducted additional Hg sampling at the Navajo and Coronado Generating Stations to enhance their understanding of Hg emissions from these two coal-fired facilities and the challenges of testing for Hg in flue gas. The commenter notes that both stations were part of the 1999 ICR where the Ontario-Hydro method was used for Hg sample collection. Attachment 1 to the commenter's letter contains the test results and a brief description of sampling protocols.

Response:

The Agency appreciates the data and is evaluating it.

Comment:

One commenter (OAR-2002-0056-2101) stated that, in reference to Method 324, if a separate particulate filter is used in front of the trap, this filter may easily absorb gaseous Hg species during a long sample run. Is the inlet filter material analyzed along with the sorbent material? If so, the method measures particulate Hg as well as gaseous. Unless iso-kinetic sampling is done, the particulate fraction may be over or under represented. If the particulate filter material is not analyzed, the danger exists that gaseous Hg has deposited on it and will be discarded along with the material. This would cause serious under-representation of the gaseous phase Hg.

Response:

40 CFR part 75, Appendix K in the final rule specifies that sorbent media should be the first thing to contact stack gas.

Comment:

One commenter (OAR-2002-0056-2101) stated that, in the proposals, CEMs require that stack flows be monitored exactly in order to allow calculation of an accurate emission rate. However, in the proposed Method 324, even when variable flow rates that track emission volumes are required (only for samples of >12 hours duration), the sampling flow rates need agree only within ±25 percent of stack velocity and only over a 3:1 dynamic range. This wide error allowance will produce inaccurate mass emission calculations.

Response:

Appendix K of 40 CFR part 75 requires that the output from a part 75 certified stack gas flow monitor be used to maintain a proportional sample flow rate through a sorbent trap across all load levels, not just the three specified in the SNPR. Most of the affected sources under the final rule are subject to the Acid Rain Program or to the NO_x Budget Program (or both) and already have the required stack gas flow monitor. The final rule retains the requirement to maintain a constant (± 25 percent) ratio of stack gas flow rate to sample flow rate from hour-to-hour. EPA will evaluate sorbent trap system data as time goes on, to see whether the ± 25 percent criterion needs to be tightened.

Comment:

Two commenters (OAR-2002-0056-2485, -3455) noted that, in reference to proposed Method 324 (40 CFR part 63), section 8.2.1 (Sample Collection), page 4738, an isolation valve is shown in Figure 324-1. The method should suggest closing the valve to prevent negative or positive flow due to stack gas pressure. This would also allow the tube to heat to the correct temperature before commencement of sampling.

Response:

The sorbent media monitoring requirements (formerly Method 324) have been revised to make them performance based providing additional flexibility as well as performance criteria used to assess the quality and validity of the monitoring data generated. The drawing referenced by the commenters is now offered as one example of a suitable sampling train configuration. There are numerous potential approaches for gas control and the performance based approach intentionally avoids specifying that level of detail.

Comment:

One commenter (OAR-2002-0056-2101) noted that, in reference to Method 324, section 8.2.3 (Flow Rates), because the method returns a true dry concentration, the instantaneous stack flow rate must also be a true dry value. However, the velocity measurement is a normally wet value. This requires one of the following:

- Verification that stack moisture levels do not vary significantly with velocity or over time;
- A moisture analyzer to allow calculation of dry flow rate;
- Some other precise and accurate method of determining current moisture levels; or
- An error analysis showing that the worst case errors introduced by failing to perform this correction are not significant.

Response:

The final rule requires that Hg concentrations and stack gas flow rates used to calculate Hg mass emissions must be on the same moisture basis.

Comment:

Two commenters (OAR-2002-0056-2101, -3455) stated that, in reference to proposed Method 324 (40 CFR part 63), section 8.2.6 (Moisture Knockout), page 4738, the section should state that data for the entire run period must be invalidated in the event that the leak check fails. This is because the dry gas flow meter may have been sampling after the sorbent cartridge, not through it, resulting in low Hg readings.

Response:

EPA agrees. Table K-1 in Section 8.0 of Appendix K specifies that failure to meet the post-test leak check criterion will invalidate the sorbent trap monitoring data.

Comment:

Two commenters (OAR-2002-0056-2101, -3455) stated that, in reference to proposed Method 324 (40 CFR part 63), section 8.3.4 (Field Spikes), page 4738, this section gives the impression that the Hg is spiked onto the cartridges before exposure. (This procedure should possibly be renamed to lab spike, rather than field spike.) This procedure yields very little information. Unless the sample gas matrix actually causes the removal of existing Hg on the trap, or interference with the analysis, this procedure will always generate 100 percent recoveries. Even if Hg is spiked onto the cartridges after sampling, this does not provide definitive proof that Hg was being properly captured under actual sampling conditions. Commenter OAR-2002-0056-2101 suggested that a more valid type of spike test would be to spike the cartridges in situ, under actual sampling conditions, towards the end of a lengthy sampling period. This could be done by adding a high concentration of a gas containing elemental (or ionic) Hg. Spiking would be done at a low flow rate (e.g., 100 ml/m). This spike gas would be sent to the probe, directly in front of the cartridges and the spike duration would be chosen to produce a significant additional loading on the cartridge. Because the spike gas is produced at a rate significantly below the cartridge sampling rate, all of the spike would be drawn through the cartridge and none would be lost out of the tip of the probe. Only in this way can one be assured that Hg is being captured quantitatively throughout the entire measurement period. The spiking gas would have to be introduced at a known flow rate and with a known concentration. A conventional saturated Hg vapor generator would suffice.

Response:

In the final rule, Appendix K requires spiking of the third section of each sorbent trap with elemental Hg prior to sampling. The purpose of the spiking is to serve as a QC check of the laboratory performing the analyses. EPA does not agree with the commenter's proposed spiking technique. Unless one can be assured of 100 percent recovery of the Hg in each trap (the Agency does not believe this is possible), spiking directly in front of the sorbent trap will cause the spiked Hg to become mixed with the sampled Hg, making it impossible to separate the two.

Comment:

Two commenters (OAR-2002-0056-2485, -3455) stated that, in reference to proposed Method 324 (40 CFR part 63), section 10.1 (Calibration and Standardization), page 4739, the standards should contain the same quantity of leaching agent as the samples being analyzed.

Response:

The sorbent media monitoring requirements (formerly Method 324) have been revised to make them performance based, thus providing significant additional flexibility in choice of sampling and analytical approaches, as well as performance criteria used to assess the quality and validity of the monitoring data generated. There are numerous potential approaches for sample preparation, depending upon the analytical technique selected. The performance based

approach intentionally avoids specifying that level of detail.

Comment:

One commenter (OAR-2002-0056-2867) notes that Method 324, section 11.1 states, "The sorbent traps are received and processed in a low-mercury environment (class-100 laminar-flow hood and gaseous Hg air concentrations below 20 ng/m^3) following clean-handling procedures" (69 FR 4739). The commenter recommended that the EPA not require the use of the class-100 laminar-flow hood. The commenter's experience with EPA Method 1631 for low level Hg in water indicates that processing samples in a class-100 laminar flow hood is unnecessary to maintain Hg contamination below stated levels. However, the room in which samples are processed may require restricted activity to keep contamination below 20 ng/m^3. The commenter submitted the lab should be able to achieve and maintain a low-Hg environment by the means it deems necessary. In the event that the EPA chooses to require the class-100 laminar-flow hood, the commenter requested EPA to specifically define the underpinnings for the use of a class-100 laminar-flow hood and define the requirements of a class-100 laminar-flow hood.

Response:

As noted previously, the sorbent media monitoring requirements have been revised to utilize a performance based approach. With this approach, is up to individual laboratories to utilize whatever measures they find necessary to achieve acceptable background Hg levels in order to achieve the performance criteria for the measurement.

Comment:

One commenter (OAR-2002-0056-2867) notes that section 11.14 of Method 324 states, "A field blank is performed by assembling a sample train, transporting it to the sampling location during the sampling period, and recovering it as a regular sample. These data are used to ensure that there is no contamination as a result of the sampling activities. A minimum of one field blank at each sampling location must be completed for each test site" (69 FR 4740). The commenter believed the requirement to assemble an entire sample train to make a field blank is excessive. The commenter asserted a field blank does not need to be attached to a separate sample train. The commenter stated simply handling the field blank trap along with the actual test sample trap at the test location and then sending it to the lab for analysis will fulfill the goals of the field blank. The commenter recognizes that the requirements for a field blank should be based on actual test data. The commenter requests that the EPA publish the test data on which the field blank requirements are based. The commenter stated that EPA should provide data that indicate that the process of sample train preparation and sample recovery can introduce significant contamination into the sampling procedure, if this is indeed a requirement.

Response:

As noted previously, the sorbent media monitoring requirements have been revised to utilize a performance based approach. Blanks, including reagent blanks, method blanks, and field blanks can be used at the tester's option to assess sources and levels of sample contamination. Blank correction, however, is not allowed.

Comment:

Two commenters (OAR-2002-0056-2101, -3455) noted that, in reference to proposed Method 324 (40 CFR part 63), section 11.14 (Field Blanks), page 4739, this section does not say what is to happen with results that exceed 30 percent of the measured value. The data should be considered invalid.

One commenter (OAR-2002-0056-3455) stated that, in reference to proposed Method 324 (40 CFR part 63), section 11.14 (Field Blanks), page 4739, Table 324-2 the table should be completed so the corrective action is available for all QA/QC failures.

Two commenters (OAR-2002-0056-2485, -3455) stated that, in reference to proposed Method 324 (40 CFR part 63), section 11.4 (Mercury Reduction and Purging), page 4739, the suggested field blank of 30 percent of the measured value is much too high. Surely it would be more sensible to define the field blank in absolute mass as per table 324-2. If a trap has a max capacity of 1,800 µg then this would equate to 540 µg, which would be a serious contamination issue.

Response:

As noted above, the sorbent media monitoring requirements have been revised to utilize a performance based approach. Blank samples are not required, but are rather used at the tester's option to assess sources and levels of sample contamination. Blank correction is not allowed and there are no criteria for acceptable blank levels.

Comment:

Two commenters (OAR-2002-0056-2485, -3455) stated that, in reference to proposed Method 324 (40 CFR part 63), section 11.3 (Dilution Step), page 4739, the dilution volume is not specified but potentially very large dilutions are required to fit into the calibration range of Method 1631.

Response:

As previously noted, the sorbent media monitoring requirements have been revised to utilize a performance based approach. With this approach, it is up to individual users to select suitable analytical techniques and associated sample preparation steps in order to achieve the

performance criteria specified for the measurement and thus dilution steps are no longer specified.

Comment:

One commenter (OAR-2002-0056-2867) stated that sections 11.0 through 11.4 define the analytical procedure of Method 324 and use a water digestion method. The commenter submitted that the rule should include an avenue for approval of an alternate ASTM analytical procedure, if the alternate method is shown to provide comparable results (similar to use of ASTM methods for the analysis of coal and ash).

One commenter (OAR-2002-0056-2485) noted that, in reference to Method 324, section 11.4, the selection of the EPA 1631 as the preferred method to analyzed the sorbent tubes has no scientific justification. This method is extremely complex and only the most specialized laboratories have the necessary resources to run this procedure. The commenter also noted that, in reference to Method 324, section 11.4, the Method 1631 method has many requirements that are not appropriate or needed to analyzed sorbent traps. The 1631 method specifies the use of amalgamation on gold to decrease detection limits. This is not necessary because the concentrations in the final solution are sufficiently high. The amalgamation step complicates the measurement and introduces more error.

Two commenters (OAR-2002-0056-2485, -3455) noted that, in reference to Method 324, section 11.4, the Method 1631 method has many requirements that are not appropriate and needed to analyzed sorbent traps. The 1631 method specifies an oxidation using BCL. Is this step necessary as the Hg species will be already digested during the leaching process? What is the purpose of the BCL?

The commenters also noted that, in reference to Method 324, section 11.4, the Method 1631 method has many requirements that are not appropriate and needed to analyzed sorbent traps. The addition of NH_2OH after the BrCl oxidation to remove free halogens is clearly specified in the 1631 method to overcome damage to the gold trap and prevent low collection efficiency (M163l, section 11.2). Method 324 states that this stage is omitted allow the free halogens will still be present. What is the justification in omitting such a critical stage of the 1631 method? Furthermore the sorbent leaching step uses a concentrated $HN0_3/H_2S0_4$ mixture at elevated temperature in a closed vessel. As mentioned in Method 324 in section 11.2 significant quantities of noxious and corrosive gases are released. These gases are likely to be NO_x fumes which may combine with BrCl to produce NOCl fumes which may also attack the gold trap and lower its collection efficiency.

Response:

As previously noted, the sorbent media monitoring requirements have been revised to utilize a performance based approach. With this approach, it is up to individual users to select any suitable analytical technique as long as it can achieve the performance criteria specified for

the measurement.

Comment:

One commenter (OAR-2002-0056-2485) noted that, in reference to Method 324, section 11.4, Method 1631 has many requirements that are not appropriate and needed to analyzed sorbent traps. The method was designed for trace levels of Hg in water not sorbent tubes. The concentration range of the method is too low (0-100 ng/L) for the expected mass of Hg on sorbent traps. For example if the flue gas Hg concentration was 1 µg/m^3 sampling for 4 hours at 0.4 L/min would yield 96 ng Hg. Insufficient information is provided in the method to calculate the final concentration of Hg in solution after sample preparation. A simple calculation however would suggest that the mass of Hg collected would have to be diluted using 1000 ml to produce 96 ng/L to be in the concentration range of the method. If one considers the maximum allowable mass collected on the small trap (150 µg) a dilution volume of l,500,000 ml. The large sorbent trap specifies 1800 µg capacity so a dilution volume of l8,000,000 ml would be required. Although these calculations represent the upper capacity limits they surely demonstrate that 1631 is not an appropriate method for the analysis of sorbent tubes and the potential error of such high dilutions

Response:

As previously noted, the sorbent media monitoring requirements have been revised to utilize a performance based approach. With this approach Method 1631 is no longer specified; it is up to individual users to select an suitable analytical techniques and associated steps in order to achieve the performance criteria for the measurement.

Comment:

Two commenters (OAR-2002-0056-2101, -3455) noted that, in reference to proposed Method 324 (40 CFR part 63), section 11.6 (Instrument Calibration), page 4739, Method 1631 uses a calibration factor approach to calibration. It does not rely on r^2 values. The method should standardize on either a weighted or unweighted regression approach to calibration because the two approaches may yield significantly different results. Note that the Method 1631 analytical approach is often used with weighted, ($1/r^2$) least squares curve fitting.

Response:

Numerous commenters stated that Method 1631 is inappropriate for the analysis of sorbent trap samples. EPA concurs, and all references to Method 1631 have been removed in the final rule. The final rule allows any suitable analytical technique to be used. For the calibration curve of the analyzer, the rule simply requires an r^2 value greater than or equal to 0.99 and requires each calibration point to be within 10 percent of the true value.

Comment:

One commenter (OAR-2002-0056-2889) stated that, in reference to Method 324, section 11.7, refers to section 15, but likely should refer to section 12.

Response:

Although the commenter is correct, the revisions to the sorbent monitoring procedures have eliminated the need for this reference.

Comment:

Two commenters (OAR-2002-0056-2485, -3455) stated that, in reference to proposed Method 324 (40 CFR part 63), section 11.8 (Continued Calibration Performance), page 4739, 10 percent drift on a calibration standard is too high. If the CV-AAS or CV-AFS has drifted 10 percent then the probability of passing a RA test is lessened dramatically.

One commenter (OAR-2002-0056-2867) noted that, in reference to section 11.9 of Method 324, EPA states, "The QA/QC for the analytical portion of this method is that every sample, after it has been prepared, is to be analyzed in duplicate with every tenth sample analyzed in triplicate" (69 FR 4739). The commenter claims these are highly excessive requirements for the QA/QC of the analytical portion of the method. The commenter recommended that the QA/QC be reduced to one duplicate every tenth sample analyzed, as allowed under other EPA's QA/QC programs. In other EPA monitoring programs such as the methods for water analysis, QA/QC requirements are limited to a duplicate and a spike for duplicate for every tenth sample. The commenter submits that if required, EPA could adopt the practices used in water monitoring programs.

One commenter (OAR-2002-0056-2867) stated that, in reference to section 11.9 of Method 324, the sorbent trap laboratory blank requirement of 3 percent analysis set of 20 sorbent traps also seems excessive. The commenter recommended one blank per every tenth sorbent trap.

One commenter (OAR-2002-0056-2889) stated that, in reference to Method 324, section 11.10, should also require the independently prepared samples to be within 10 percent of the expected value.

Response:

As previously noted, the sorbent media monitoring requirements have been revised to utilize a performance based approach and this level of detail is no longer specified. Laboratories conducting analyses of the sorbent media cartridges for Hg must either be ISO certified or accredited or must perform the spike recovery study described in Appendix K of 40 CFR part 75 annually. Thus, adequate QC procedures will be in place to ensure the quality of

the data.

Comment:

One commenter (OAR-2002-0056-2889) stated that, in reference to Method 324, section 11.13, should in the last sentence refer to 10 percent of the measured sample results.

Response:

The commenter is referring to a requirement for solution blanks. As noted above, the sorbent media monitoring requirements have been revised to utilize a performance based approach. Blank samples are not required, but are rather used at the tester's option to assess sources and levels of sample contamination. Blank correction is not allowed and there are no criteria for acceptable blank levels.

Comment:

One commenter (OAR-2002-0056-2889) stated that, in reference to Method 324, section 13.0, should specify the consequences of failing to achieve the required sample rate per stack flow. Another commenter (OAR-2002-0056-2485) stated that, in reference to Method 324, Table 324-2, the table should be completed so the corrective action is available for all QA/QC failures.

Response:

EPA agrees. Table K-1 in Appendix K specifies that failure to achieve certain performance or acceptance criteria will invalidate the sorbent trap monitoring data.

Comment:

One commenter (OAR-2002-0056-2485) stated that section 13.0 of Method 324 is confusing.

Response:

EPA agrees and has clarified the flow-proportional sampling requirements in Appendix K of 40 CFR part 75.

Comment:

One commenter (OAR-2002-0056-3455) stated that, in reference to proposed Method 324 (40 CFR part 63), section 13.0 (Constant Proportion Sampling), page 4740 and section 8.2.4 (Constant Proportion Sampling) Option 1 & Option 2, these sections are confusing. If these criteria were to be followed, a source could set their flow rate based on 75 percent of maximum possible stack flow and be in compliance continuously from 50 percent of flow to 100

percent of flow. However, the commenter believes that this would result in significant under reporting of full load data and over reporting of reduced load data. The results of this could greatly reduced Hg emission rates. Load following is the only way to make this work and it should have the same standards as Method 5 sampling (+/-10 percent). Simply picking a sample flow rate as suggested in the amended sections is not appropriate either.

Response:

EPA understands the commenter's theoretical concern and will evaluate additional data from actual units to see whether the permissible deviation criteria needs to be tightened in the future.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2861, -2922, -3565) stated that several provisions, including sections 13 and 14, purport to contain requirements for calculations and data analysis. These sections are inadequate. These sections should contain all of the equations and calculations needed to conduct the method and arrive at Hg emissions values that are either in the units of applicable standards or that can be converted to those units. Procedures for incorporating blank determinations should also be included.

Response:

EPA has addressed the commenters' concerns in finalizing the sorbent monitoring procedures; however, the final procedures do not include provisions for blank correction.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2861, -2922, -3565) stated that the proposed Method 324 appropriately requires leak checks of the sampling line with and without the sorbent trap in place. The checks are performed using a rotameter. The commenters are concerned that with a nominal flow rate of 0.4 L/min (see Table 324-1), 2 percent of that flow rate (which is the maximum leakage allowed under the proposal) may be too low to be accurately read on a standard rotameter. Accordingly, the commenters suggest that EPA consider revising the Method 324 to quantify the leak rate based on readings from the dry gas meter over a period of at least 1-minute.

Response:

EPA understands the commenters' concerns and has revised the leak check procedures to clarify that the dry gas meter should be used to quantify the leak rate. The leak check specifications have also been revised to allow a leak rate up to 4 percent of the planned (pre-test leak check) or 4 percent of the average sampling rate (post test leak check) which is consistent

with Method 5 (40 CFR 60, Appendix A).

Comment:

One commenter (OAR-2002-0056-2867) pointed out that Table 324-1 (69 FR 4738) of Method 324 states that the maximum sample duration for the large sorbent trap is 10 days. The commenter recommended that the maximum sample duration not be limited at this time. The commenter stated that requiring short sampling periods adds to the cost of the monitoring process, as the traps will have to be changed more frequently. The commenter's experience indicated that changing the sample trap results in approximately 30 minutes of unmonitored time. The 10-day sorbent trap stipulation as proposed would lead to increases in the amount of unmonitored time, as compared to a longer sample period, which requires changing less frequently. The commenter submitted that the use of shorter length traps also increases handling, analysis, and operations support compared to a longer sampling trap. This extra handling and analysis will also introduce more opportunity for error. The commenter recommended that the sample period comport with capabilities of the carbon traps. The commenter's experience shows that the traps can be designed and used for longer sampling periods. In recent tests, the commenter compared the results of two smaller sorbent traps (one 10-day and one 11-day sorbent trap) to one large trap (a 21-day sorbent trap). The commenter claimed the test demonstrates that the results are comparable and not dependent on the length of the sample period or size of the trap (the commenter submitted an attachment with the test results). The commenter pointed out that the percent difference between the weighted average concentration measured in the two smaller traps versus the larger trap is 13.7 percent. This is well within the RA range proposed by EPA of 20 percent when comparing methods to Ontario-Hydro (69 FR 12419). The commenter has plans for further development of Method 324 to lengthen the sample duration. The commenter envisioned that the capabilities of the sorbent technology will improve with time, leading to longer duration sample collection. In this context, the commenter recommended that EPA should instead focus on the accuracy of information and not arbitrarily limit the sampling period to 10 days or a month.

Response:

EPA has revised the sorbent monitoring procedure to be performance-based and has eliminated the 10-day limit on sampling duration leaving it up to the tester to identify a sampling duration that provides the correct balance between convenience and performance.

Comment:

One commenter (OAR-2002-0056-2485) stated that, in reference to Method 324, Table 324-2, the table should be completed so the corrective action is available for all QA/QC failures.

Response:

EPA agrees. Table K-1 in Section 8.0 of Appendix K specifies that failure to achieve the

performance or acceptance criteria will require corrective action in some cases, and in other cases will invalidate the sorbent trap monitoring data.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2861, -2922, -3565) stated that Table 324-2 sets out the QC requirements for samples. The commenters are concerned that some of these requirements are excessive or not sufficiently explained or studied. For example, the requirement for laboratory blanks could be excessive for large trap lots. And, without more data, it is not possible to determine whether the paired train criterion (which is not set out anywhere else in the rule) is subject to the same problems as PS-12A, section 8.6.6. Finally, the field spiking requirement is not sufficiently explained. These problems are explained more fully in RMB's comments.

Response:

As noted previously, the sorbent media monitoring requirements have been revised to utilize a performance based approach. Blank samples are not required, but instead are used at the tester's option and, therefore, there are no criteria for acceptable blank levels. The paired train performance criterion has been based on actual levels achieved during several EPA demonstrations as well as stakeholder supplied data. The field spiking requirement has been replaced with a cartridge spiking requirement for QA and normalization of the data; this new procedure has been adequately detailed.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2861, -2922, -3565) stated that because Method 324 is a test method itself, they believe that EPA could justify a rule that did not require a RATA for validation of the sorbent trap system. The commenters are not aware of any other instance where EPA had required that an EPA test method be compared to another test method using RATA procedures prior to use to determine compliance. Use of the RATA in this case is unusual given the mixed performance of the Ontario-Hydro method that would be used for the RA test. Because Method 324 is a new method that has not been employed in practice, the commenters are not objecting to an annual RATA requirement. Such testing in the early years of the program could provide valuable information for improvement of both methods. However, the commenters would object to any more frequent testing. Method 324 already provides significant QA/QC in its sampling and analysis procedures and additional RATA testing would be unwarranted.

Response:

EPA does not believe that the sorbent media measurement procedure has the quality to serve as a reference method. However, we are confident in its performance as a monitoring technique. We have reconsidered the RATA requirements for sorbent monitoring systems and

concluded that a yearly RATA plus enhanced performance-based QA measures in Appendix K should suffice to provide accurate measurements.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2861, -2922, -3565) stated that similar to proposed PS-12A, section 8.1.1 of Method 324 proposes to require testing for SO_2 and NO_x stratification at the proposed installation location. This requirement is not consistent with other EPA regulations and should be revised to deem the location suitable as long as the RATA is passed. As in EPA's other rules, stratification testing should only be required if the source uses a wet control device (or is otherwise expected to have stratification) and exercises the option to use the short measurement line or a single measurement point during RATA testing.

Response:

The provisions of Method 324 have been revised and placed in 40 CFR part 75, appendix K. Appendix K suggests (but does not require) that stratification testing be used to site Hg monitors.

Comment:

Several commenters (OAR-2002-0056-3455, 2485) noted that, in reference to proposed Method 324 (40 CFR part 63), section 8.1.6 (Pre-Test Leak Check), page 4738, a leakage rate of less than 2 percent of the recommended flow rate of 0.4 L/min equates to less than 0.008 L/min. This flow rate is not measurable using a flow rate in the range of the method (0 - 0.8 L/min). A leak check under vacuum would be more effective and accurate.

Response:

EPA agrees that the leak checks should be conducted under vacuum. The pre-test leak check specifies ~15" Hg vacuum, while the procedures have been revised to specify that the post test leak check be done at the maximum vacuum reached during sampling. In addition, the leak check specifications have been revised to permit a leak rate up to 4 percent of the planned (pre-test leak check) or 4 percent of the average sampling rate (post test leak check) to be consistent with Method 5 (40 CFR 60, Appendix A).

Comment:

One commenter (OAR-2002-0056-2485) noted that, in reference to Method 324, section 1.0, the title is misleading as the sorbent trap is not dry during sampling and it is quite likely that a fraction of the particulate Hg is sampled because no filtration is used.

Response:

The provisions of Method 324 have been revised and placed in 40 CFR part 75, appendix K.

Comment:

One commenter (OAR-2002-0056-2485) stated that, in reference to Method 324, section 6.1.2, presumably, the large and small sorbent traps have the same type of sorbent material. Suggesting the use of larger sorbent tubes at higher duct temperatures would imply that breakthrough of Hg is potentially a problem at temperatures of 375 ˚F. The length of the probe holding the sorbent tubes is not specified. It is quite common for the flue gas to be saturated with water so unheated sorbent traps may be subjected to condensation. Surely it is advisable to heat the sorbent traps above the stack gas temperature for all applications.

One commenter (OAR-2002-0056-3455) stated, in reference to proposed Method 324 (40 CFR part 63): It is quite common for the flue gas to be saturated with water so unheated sorbent traps may be subjected to condensation. Surely it is advisable to heat the sorbent traps above the stack gas temperature for all applications. Our opinion is the specified operating temperature of the sampling probe for Method 324 is too low. Experience and data taken in the field have pointed out that a minimum operating temperature of 400 ˚F is required to transport oxidized Hg, unless the sample probe is recovered along with the sorbent tubes.

One commenter (OAR-2002-0056-2867) stated that their experience indicates that further development of the Method 324 for use on a wet stack is necessary and can be accomplished in the days ahead. The commenter noted that the original sampling probe does not work in a wet stack. Condensation builds up in the trap, and renders the sample suspect. The commenter stated that in order to sample in a wet stack, the trap must be inside a heated probe. The commenter pointed out that Method 324 addresses this issue in section 6.1.2 and states that the sampling probe must be heated in duct temperatures less than 200 ˚F, which equate to wet stacks.

Several commenters (OAR-2002-0056-2634, -2718, -2861, -2922, -3565) stated that one important aspect of the Method 324 measurement is avoiding condensation in the sorbent trap by heating the sampling probe in those conditions where the gas stream may fall below the condensation point. Section 6.1.2 requires use of a heated sampling probe for effluents below 200 ˚F as measured with a thermocouple. The commenter suggest the lower boundary of the range be increased to 250 ˚F to ensure that no water droplets form in the sorbent trap.

One commenter (OAR-2002-0056-2867) requests that, in reference to Method 324, section 6.1.2, EPA confirm that using a heated probe does not introduce differences into the procedure for obtaining a dry stack sample and wet stack sample. The commenter contends that any introduced differences are not quantified at this time, and should be investigated further. Questions the commenter requests be answered include:

- What are the differences between the heated probe and normal probe?
- Will the differences introduce any variations into the dry/wet stack sampling process?
- Does the heated probe effectively capture the Hg in the stack?
- If the heated probe is used on the wet stack, can it be used on all stacks to avoid introducing differences between the wet stack/dry stack methods?
- Is this a sufficient work around for the wet stack problem?

Response:

EPA agrees that the commenters' concerns are all valid. However, the revised sorbent monitoring requirements are performance-based and so achievement of the performance criteria will assure that these issues have been effectively managed for each sample. The final sorbent monitoring provisions advise the user that these are important issues to consider in developing their sampling strategy.

Comment:

One commenter (OAR-2002-0056-2101) stated that the preamble should clearly say that Method 324 is intended as a measurement method, and not a reference method. This commenter asked if, in reference to Method 324, section 1.0 (AF vs AA), tests have been done to confirm that atomic absorption (AA) gives answers equivalent to atomic fluorescence (AF) under all circumstances? Method 1631 is a performance based AF method that allows substitution of AA provided that QA/QC criteria are met, however this method was originally intended for simple matrices like waste waters, not extracts from flue gas. (It should be noted that this reviewer is not aware of any laboratories that have achieved true Method 1631 class performance with AA based systems, even for the simpler matrices.) EPA should exercise extreme care to ensure that AA techniques will always yield identical results to AF techniques.

One commenter (OAR-2002-0056-2485) stated that Method 324 should also be subjected to the same RA test as the HgCEM.

One commenter (OAR-2002-0056-2867) stated that Method 324 should be considered as a viable reference method. The Ontario-Hydro method is the currently accepted reference method for measuring Hg concentration in a flue gas. EPRI's experience shows that Method 324 has less variability than the Ontario-Hydro method in side-by-side comparisons (as previously seen in Attachment 1). Method 324 is also a continuous monitoring system, whereas the Ontario-Hydro method measures the Hg concentration for a snapshot of time. Thus, Method 324 has considerable advantages over the Ontario-Hydro method as a reference method. Once EPA incorporates Method 324 as a reference method, a natural extension will be to use it to monitor Hg emissions all the time or as a test audit for Hg CEMS. This argument is enhanced by the underpinnings in other CEMS activities, where the reference method is used to periodically check the daily monitoring method or can be used for daily monitoring in lieu of CEMS.

One commenter (OAR-2002-0056-2867) stated that for applications where Hg CEMS are used and for Hg monitoring and audits to be advanced, a real time instrumental reference method for RA audits is needed. EPA must develop such an instrumental reference method for Hg.

Several commenters (OAR-2002-0056-2485, -3455) suggested that Method 1631 was not an appropriate method to analyze sorbent traps for many reasons.

One commenter (OAR-2002-0056-2485) noted that, in reference to Method 324, section 2.0, this section states that other recognized procedures can be used for the analysis of sorbent tubes such as ASTM D6784-02 and method 29. Neither of these methods is suitable for this application. Both methods use various impinger solutions none of which relate to the chemistry used to leach the sorbent tubes. Suggesting the use of these methods will ultimately create confusion and the method open to interpretation. For example the ASTM method has digestion and preparations for KCl, $H_2SO_4/KMnO_4$ and H_2O_2/HNO_3 impingers. Which digestion or procedure should be used for the sorbent tubes? Furthermore CV-AAS and CV-AFS should ideally have matrix matched standards for calibration procedures so what type of standardization should be used for sorbent tube leachate? The CEN 13506 methods, EPA 245.7 and 245.1 are more appropriate options because they do not use amalgamation and have wider dynamic ranges.

One commenter (OAR-2002-0056-2040) proposes an alternative analytical technique to analyze Hg sorbent tubes for proposed Method 324. This technique involves direct (no sample preparation) Hg analyzer Lumex RA 915+ with Attachment Pyro915/RP91C for testing of iodated carbon sorbent from the tubes as an alternative to chemical digestion with following atomic fluorescent analysis of tubes. The advantages of this technology compare to proposed in Method 324 as follows:

- Technology is based on field portable Atomic Absorption spectrometry with Zeeman correction coupled to a furnace heated to 800 degrees C wherein Hg is converted from a bound state to the atomic state by thermal decomposition in a two-section furnace. In the first section of the furnace the “light” Hg compounds are preheated and burned. In the second section a catalytic afterburner decomposes “heavy” compounds.
- Direct, onsite testing of tubes. Save time for shipping, generating of chain of custody, and wait for laboratory results.
- Testing results will be available within 1 hour after method 324 testing tube removed from the sampler. Analytical throughput-20 tests per hour.
- No chemical waste generated.
- NIST traceable standards used for multipoint calibration.
- Detection Level to 0.5 µg/kg is 10 times lower than concentration of Hg expected for Method 324 tubes.
- No compressed gases required.

Response:

In view of the many comments received and the Agency’s own field testing, EPA has

decided to rename proposed Method 324, and to revise it with detailed, performance-based QA standards and procedures for sorbent trap monitoring systems. These new standards and procedures are now included in 40 CFR part 75, Appendix K, of the final rule. EPA believes that by taking this action, there will be less confusion and more convenience for users affected by the Hg cap and trade program. Because the sorbent trap monitoring system requirements in Appendix K are performance-based, the results of any analytical technique meeting the performance criteria should be comparable to any other analytical technique meeting the same performance criteria.

EPA did not propose Method 324 as a reference method, but rather as a set of analytical and QA procedures for sorbent traps to be used in a Hg monitoring program. The Ontario-Hydro Method is the reference method for Hg in part 75 of the final rule. However, EPA is developing a Hg instrumental reference method as part of the Agency's field tests of Hg monitoring systems.

Comment:

One commenter (OAR-2002-0056-3455) noted that, in reference to Appendix A to the Preamble--Proposed Changes to Parts 72 and 75, (Proposed Rules March 16, 2004); page 12417, EPA stated that sorbent trap systems can't be calibrated with cylinder gas (in description of Alternative 2, page 12417); although this may be true, it does not mean that their performance can't be checked. The lack of QA/QC and method validation is a very disturbing approach to proposing a new sampling method. It is common knowledge in the measurement industry that carbon traps can become passivated in the presence of flue gas constituents. In addition to becoming passivated, traps are also prone to re-releasing Hg after long-term exposure to flue gas constituents, thus creating a situation that would seriously under report Hg concentrations, and unfortunately, the use of the second section in the trap does nothing to address either of these problems.

Two possible solutions to this problem exist: (1) one trap in a pair could be spiked and placed in a dual sample train, when the train is analyzed the spike could be subtracted and the result should then match with the second train that was not spiked; or (2) one of the traps in the paired sample could be exposed to a Hg calibration gas near the end of its sample period, this spike could then be subtracted from the value of the spiked trap and that value compared to the trap that was not spiked. If the value of the reference trap and the spiked trap minus the spike do not match (i.e., within +/- 20 percent) then the data should be invalidated.

One commenter (OAR-2002-0056-2101) stated that, in reference to Method 324, the periodic RATA test against a reference method will not be effective in ensuring that the method is producing accurate results. This type of test is not capable of detecting cartridge passivation during lengthy Method 324 runs. Passivation is expected to occur relatively late in a sample run. Total sample volumes passed through a collection cartridge during a RATA test may be only a few percent of the total volumes that will be passed through the cartridges during normal sampling.

Response:

Extremely high stack gas temperatures (greater than about 350 deg F) required for passivating sorbent material are not expected. On wet stacks, 40 CFR part 75, appendix K, states that sorbent traps may need to be heated above the dew point to prevent condensation. Therefore, matrix effects that cause passivation or loss of Hg trapping efficiency should not be a problem. However, EPA will be examining this issue further during our field testing of sorbent media.

Comment:

One commenter (OAR-2002-0056-2867) stated that in the SNPR Section B.3., "Use of Mercury CEMS and Sorbent Trap Systems," the EPA proposes in Alternative 2 that the sorbent trap method can be used by any source, with an annual 9-run RATA and quarterly 3-run RAA required for QA. The commenter maintains that these QA requirements are excessive and the results (pass/fail/bias) will remain unknown for days and weeks. The commenter also stated that elsewhere, the EPA stated, "For sources with annual Hg emissions below the specified threshold value, the QA requirements for sorbent trap monitoring systems would be less, with only an annual RATA being required" (69 FR 12417). The commenter recommends that the QA requirements for sorbent traps - all units, irrespective of emission rates - be consistent and limited to an annual RATA, although the RATA may be unnecessary if Method 324 is ultimately is adopted as a reference method. The commenter stated that the accuracy of the sorbent trap method does not decrease with increasing unit size or larger Hg emission rate. The commenter also stated that the EPA also stated "the Agency is willing to consider replacing the RAA requirement with another type of substantive quarterly QA test, if commenters who favor the use of sorbent trap systems are aware of, and can provide details of, any such test or procedures" (69 FR 12417). The commenter recommends that if quarterly checks are deemed necessary, the EPA might include semiannual analysis of spiked and blank traps, and quarterly sample flow checks and pump calibrations.

Response:

See Sorbent Trap Operation and QA/QC discussion in the preamble.

Comment:

Several commenters (OAR-2002-0056-2079, -2485, -2634, -2718, -2861, -2922, -3455, -3565) were generally opposed to the proposed quarterly relative accuracy audits (RAAs) for sorbent trap systems as being too costly and of little value. A number of commenters suggested that EPA should revise proposed Alternative #2 and specify QA procedures that are meaningful to the type of measurement system that the sorbent trap actually is. For example, the volume of stack gas sampled by the system is an important parameter in determining the Hg concentration. Therefore, procedures for quality-assuring the measurement of the sample volume could be implemented.

Some commenters favored allowing the use of proposed Method 324 for all affected units, and stated that because Method 324 is itself a test method, it does not need additional QA procedures. Two commenters suggested that EPA should even take steps to make Method 324 a reference method. However, numerous other commenters objected to various provisions of proposed Method 324 and offered suggestions for improving it. Some of the chief objections raised were as follows:

- The allowable analytical techniques and procedures in the method are too exclusive, and in the case of Method 1631, inappropriate. Other analytical methodologies should be allowed;
- The impinger and dessicant method of moisture removal is inadequate;
- The leakage rate prescribed for the leak checks checks may be too low to measure;
- The method allows constant-rate sampling for collection periods less than 12 hours, which may introduce bias if unit load changes during the collection period;
- The specification for flow proportional sampling (adjust sample flow rate to maintain proportional sampling within $\pm$ 25 percent of stack gas flow rate) is not stringent enough and can lead to inaccurate concentration measurement;
- The frequency for dry gas meter calibration is unspecified; and
- The method does not include chain of custody procedures.

A number of commenters suggested that EPA should not require the use of paired sorbent traps and should allow the use of single sorbent traps.

Several commenters objected to the proposal in section 1.5.4 of Appendix B that laboratories performing Method 324 be certified by the International Organization for Standardization (ISO) to have proficiency that meets the requirements of ISO 9000. One commenter stated that having a good blank and matrix spike program in place is much more indicative of a good QA/QC program for Hg measurement than ISO 9000 certification. Another commenter favored ISO certification, but not according to ISO 9000. The commenter recommended that ISO 17025 be required instead, because it requires the laboratory to demonstrate proficiency, rather than simply having an acceptable protocol for the analyses.

One commenter stated that EPA has not explained the appropriateness of applying a bias test and adjustment factor to Method 324, when it has already satisfied the same standards for bias and precision as the Ontario-Hydro Method under EPA Method 301. Another commenter suggested that it does not make sense to subject Hg monitors to a bias adjustment factor under Appendix A, section 7.6 when paired reference method trains are allowed to differ by 10 percent relative deviation (RD), based on a flawed definition of RD. The commenter asserted that it is not reasonable to suggest that a Hg monitor is biased by comparing its readings to a pair of reference method tests that can differ by 20 percent.

One commenter (OAR-2002-0056-2867) stated that their current experience with Method

324 (QSEMS) indicates that component reliability has to be improved. The commenter's experience indicates issues with the following:

- Flow meter (Totalizer) -Typical problems encountered are a delayed start to recording the data and discontinuous recording of data after several days.
- Sampler Pump - Readings vary by ±25 percent when set at constant flow. The flow rate also decreases overtime as particulates build up.
- Currently O_2 cannot be measured and recorded with this device. Correcting to 3 percent O_2 is the typical way to compare individual test runs and to allow the detection of leaks on line during the sampling period.
- The carbon trap plugs in high ash situations. The method will not work upstream of an ESP without an inertial separator or other method to remove the ash.
- For wet stack application the probe will need modification.

The commenter asserted that these changes are required before QSEMS can be relied on to demonstrate compliance. The commenter notes the industry is investing time and money into the development of these systems, to enhance reliability by 2010. The commenter contends it is important that the compliance deadline not be moved earlier than 2010.

Response:

In view of the many comments received and the Agency's own field testing, EPA has decided to rename proposed Method 324, and to revise it with detailed, performance-based QA standards and procedures for sorbent trap monitoring systems. These new standards and procedures are now included in 40 CFR part 75, appendix K, of the final rule. EPA believes that by taking this action, there will be less confusion and more convenience for users affected by the Hg cap and trade program. Today's rule also revises both the definition of a sorbent trap monitoring system in section 72.2 and the general guidelines for sorbent trap monitoring system operation in section 75.15, to be consistent with the QA requirements of Appendix K.

The final rule retains the annual RATA and bias test requirements for sorbent trap monitoring systems, but the proposed quarterly RAA requirement has been withdrawn. The requirements to use paired traps and flow proportional sampling have also been retained. Finally, the ISO-9000 certification requirement for the laboratory performing the Hg analyses has been replaced with a requirement for the laboratory to either comply with ISO-17025 or to comply initially, and annually thereafter, with the spike recovery study provision in section 10 of 40 CFR part 75, Appendix K.

Several commenters recommended that EPA should require QA procedures for sorbent traps that are more meaningful and reasonable than the procedures in the SNPR. EPA agrees with these comments, and based on the recommendations received, today's rule specifies such procedures in Appendix K. Many provisions of Method 324 have been included in Appendix K without modification, but other provisions of the method have been modified and some new QA procedures have been added to address concerns expressed by the commenters. Some of the

more significant differences between Method 324 and Appendix K are as follows:

- *Appendix K allows the use of any sample recovery and analytical methods that are capable of quantifying the total vapor phase Hg collected on the sorbent media. Candidate recovery techniques include leaching, digestion, and thermal desorption. Candidate analytical techniques include ultraviolet atomic fluorescence, ultraviolet atomic absorption, and in-situ X-ray fluorescence;*
- *Appendix K requires that each sorbent trap be comprised of three equal sections, the first one for sample collection, the second to assess "breakthrough", and the third to allow spiking with elemental Hg, for QA purposes;*
- *Appendix K specifies the frequency of dry gas meter calibration, and the appropriate calibration procedures;*
- *Appendix K requires ASTM sample handling and chain of custody procedures to be followed.*
- *Spiking of the third section of each trap with elemental Hg is required before each data collection period begins.*
- *The laboratory performing the analyses must demonstrate the ability to recover and quantify Hg from the sorbent media*
- *The measured Hg mass in the first and second sections of each trap is adjusted (normalized), based on the percent recovery of Hg from the third ("spiked") section.*

EPA believes that if these procedures are implemented, this will ensure the quality of the data from sorbent trap systems.

The final rule retains the requirement to use paired sorbent traps. The SNPR proposed the use of paired sorbent traps for the same basic reason that paired Ontario-Hydro trains are required for RATA testing, i.e., it provides an important check on the quality of the data. The proposed rule would have required the higher of the two Hg concentrations obtained from the paired traps to be used for reporting. However, the final rule requires the results from the two traps to be averaged if they meet specified criteria, and allows the results from one trap (if those results are valid) to be reported in cases where the other trap is accidentally damaged, broken or lost during transport and analysis. Thus, using paired sorbent traps provides a relatively inexpensive means of ensure against data loss should one of the traps become lost or damaged.

The commenters generally objected to the proposed quarterly relative accuracy (RA) testing of sorbent traps, believing it to be unnecessary and costly. After consideration of recent field data comparing the sorbent traps to Hg CEMS, EPA agrees that sorbent trap systems should be treated more similarly to Hg CEMS. Therefore, the final rule removes the quarterly RAA requirement, and requires only that an annual RATA be performed on a sorbent trap monitoring system.

One commenter objected to the proposed bias test requirement for sorbent trap systems, citing the fact that Method 324 had satisfied the same standards for bias and precision as the

Ontario-Hydro Method under EPA Method 301. EPA does not agree with this comment. The fact that Method 324 met the bias and precision requirements of Method 301 does not imply that Hg sorbent traps will not exhibit low bias with respect to a Hg reference method during a RATA. The bias test in section 7.6 of 40 CFR part 75, appendix A, is a one-tailed t-test, which, if failed, requires a bias adjustment factor (BAF) to be applied to the subsequent emissions data.

EPA also does not agree with the commenter who stated that bias adjustment is not appropriate for sorbent trap systems because of the allowable 10 percent RD between the paired reference method trains. The part 75 bias test determines systematic error, not random error, whereas RD and relative accuracy are metrics used to quantify random error in the measurement.

Comment:

One commenter (OAR-2002-0056-3455) suggested that, in reference to Method 324 (40 CFR part 63), section 1.1.2 (Applicability), page 4736, a Hg RATA should be performed on the same long-term time basis as the method's use of a CEMS, i.e., an applicable RATA time period equal to or greater than the longest averaging period. This may mean multiple Ontario-Hydro paired train runs during the Method 324 extended sampling time period. Moisture corrections from the Reference Method should be applied to Method 324 data for the entire averaging period. A short-term averaging period for correlation to the Reference Method does not provide long-term assurance of carbon trap performance.

Response:

The final rule requires that a minimum of 9 runs be used to calculate a RA for either Hg CEMS or sorbent traps. For the RATA of a Hg CEMS using the Ontario-Hydro Method, or for the RATA of a sorbent trap system (irrespective of the reference method used), the minimum time per run must be long enough to collect a sufficient mass of Hg to analyze. EPA has decided to implement this approach as a compromise between the desire to test the sorbent traps' long term performance and the practicality of performing a potentially week-long reference method test, with the Ontario-Hydro Method.

Comment:

One commenter (OAR-2002-0056-3455) stated that, in reference to proposed Method 324 (40 CFR part 63), section 1.1.2 (Applicability), page 4736, performance verification criteria must be established to assure that 100 percent cartridge trapping efficiency is maintained:

- Over the full permitted temperature range of the sampling train and over the full stack gas temperature range;
- Over the full flow rate range of the sampling train (especially the combination of highest temperature range with highest flow rate - which would be expected to create the highest probability of breakthrough.); and

- Over the full range of stack gas compositions. This becomes particularly important in cases where control technology is employed.

Response:

The extremely high stack gas temperatures required for passivating sorbent material are not expected to be encountered in utility stacks. On wet stacks, Appendix K of 40 CFR part 75 states that sorbent traps may need to be heated above the dew point to prevent condensation. Therefore, matrix effects that cause passivation or loss of Hg trapping efficiency should not be a problem. However, the Agency will be investigating this issue further during our field testing of sorbent media.

Comment:

Commenter OAR-2002-0056-2922 stated that section 75.15 contains the Special Provisions for using the sorbent trap monitoring method (Method 324). Section 75.15(e) specifies proportional sampling and then further explains the proportional sampling procedure as a change in the sampling rate in relation to load. This procedure is flawed and is in conflict with Method 324. Any proportional sampling method will require stack flow rate or load input into the sampling device. The sorbent traps will be located at a stack or duct location and manually making the required flow changes, at odd times of the day, will just not be feasible. EPA should make this section consistent with Method 324 and allow for automated input of stack flow or load data into the sorbent sampling system and allow for automated flow rate adjustment.

Response:

EPA agrees with the commenter and the final rule requires the flow control valve and air-tight sample pump to be controlled by the 40 CFR part 75 certified flow monitoring system. The final rule also requires that the data acquisition and handling system ensure that the sampling rate is proportional to the stack gas volumetric flow rate.

Comment:

Commenter OAR-2002-0056-2922 stated that section 75.15(i) should have the words “or partial hours” added to the first sentence.

Response:

EPA believes that the suggested change is unnecessary in light of the definition of “unit operating hour” in section 72.2 which includes “any hour (or fraction of an hour).”

6.4 QA/QC PROCEDURES FOR HG CEMS

Comment:

One commenter (OAR-2002-0056-3406) stated that given the early stages of the development of Hg CEMS technology, it is inappropriate to specify a mandatory performance specification. The commenter believed facilities subject to this requirements should have the option of proposing and complying with an alternative performance standard that provides substantially similar assurances.

Response:

The final rule contains an alternative relative accuracy performance specification for low emitting sources.

Comment:

One commenter (OAR-2002-0056-3455) suggested that, in reference to PS-12A, the final rule should change the cycle time (from the proposed fixed 15 minutes) to a field determined cycle time. Elemental Hg can achieve a 15-minute cycle, however, currently that cycle time would be difficult for oxidized Hg to achieve. EPA should continue to work with vendors with a goal of achieving 15 minute cycle times for all forms of Hg. A TGM blend will also take longer.

Response:

EPA's field testing indicates that 15 minute response times and cycle times are achievable for both elemental and oxidized Hg.

Comment:

One commenter (OAR-2002-0056-3455) suggested that, in reference to PS-12A, the CEMS should be challenged with a calibration gas blend of Hg^0 and Hg^{+2} at a frequency consistent with 40 CFR part 60, Appendix B, PS-2, introduced at the sample acquisition point, prior to any filtration; to access sample transport for data validation.

Response:

EPA agrees with the need to periodically check the performance of the entire monitoring system. EPA's field testing has shown that a single injection performed daily using the appropriate concentration of oxidized Hg is sufficient to check the upscale calibration of the Hg CEMS from the probe tip through the analyzer and the efficiency of the $HgCl_2$ to Hg converter. The final rule allows either elemental or oxidized Hg to be used to perform daily calibration checks.

Comment:

Commenter OAR-2002-0056-2922 stated that in section 60.4171(c)(2) it is not clear whether a source installing a new Hg monitoring system must submit a Certification Application. In many instances, the Hg monitoring system will be a completely separate Hg/diluent system that uses full concentration, dry basis analysis. The data acquisition system and other inputs, like stack flow rate will be associated with a previously certified part 75 system. It is not clear whether such a system would require a certification application to be submitted. It is also not clear how much of the system would need to be included in the certification application.

Response:

Section 60.4171(c)(2) states that a certification application is not required if the system has been previously certified under the Acid Rain Program or under an applicable State or Federal NO_x mass emission reduction program that adopts the requirements of 40 CFR part 75, subpart H. Therefore, e.g., if a flow monitoring system was previously certified under, e.g., the Acid Rain Program (part 75), a certification application for that flow monitoring system is not required.

The final rule removes all requirements for a Hg emission rate (or Hg-diluent) monitoring system. However, either a sorbent trap monitoring system or a Hg concentration monitoring system is required by the final rule. A Hg concentration monitoring system consists of a Hg pollutant concentration monitor and an automated data acquisition and handling system. Because neither a Hg concentration monitoring system nor a sorbent trap monitoring system was required by 40 CFR part 75 until this rulemaking, a certification application must be submitted for either of these systems.

Comment:

Several commenters (OAR-2002-0056-1969, -1975, -2040, -2046, -2063, -2068, -2073, -2079, -2160, -2181, -2206, -2224, -2244, -2252, -2259, -2260, -2267, -2296, -2365, -2379, -2380, -2429, -2485, -2578, -2718, -2721, -2827, -2830, -2833, -2835, -2844, -2862, -2867, -2877, -2889, -2891, -2898, -2900, -2918, -2922, -2929, -2947, -3200, -3413, -3436, -3443, -3444, -3454, -3458, -3487, -3559, -3568) were in general agreement on the following points. Although many vendors of Hg CEMS have recently upgraded their instrument systems and these changes should eventually improve the accuracy and reliability of Hg CEMS and reduce the labor needed for instrument maintenance, these new instrument systems have not been tested extensively in demonstration programs. Therefore, the ability of these instrument systems to achieve the proposed relative accuracy, calibration error, and calibration precision requirements has not been adequately demonstrated. Therefore, EPA does not yet have a basis or data to guide the setting of specifications for calibration error, linearity, or relative accuracy. It appears that the proposed performance specifications mirror those for SO_2 and NO_x monitoring. EPA should commit to collecting data and evaluating these specifications as soon as calibration gases are available, so that the specifications can be adjusted if necessary, prior to program

implementation. EPA should require operators of Hg CEMS to conduct procedures that include but are not necessarily limited to daily zero and span audits, quarterly relative accuracy tests and three-point elemental Hg linearity tests, and absolute calibration audits. Analytically, there is clearly a need to challenge the entire system often with a form of oxidized Hg. This Hg chloride ($HgCl_2$) reference gas would be highly desirable to check integrity of the sample interface. However, further research needs to be required to enable the development of an accurate oxidized Hg standard. One device, the Hovacal, may have the potential of delivering known concentrations of $HgCl_2$. EPA should recognize and accept this type of calibration system in the proposed regulation. There are concerns with the proposed RATA process, particularly the length of time and amount of money that may be required to comply with the Hg monitoring requirements on an annual basis. The final monitoring requirements must be technically achievable and capable of measuring Hg emissions with precision, reliability, and accuracy in a cost-effective manner. The decision to report Hg concentration on dry or wet basis needs more consideration, as well as, the evaluation of gaseous interferences. Lastly, many of the equations and calculations are incomplete or contain errors and many sections need further clarification.

Response:

In the final rule, the same tests are required for initial certification and on-going QA of Hg CEMS as were proposed in the SNPR. However, note the following changes to some of the procedures and performance specifications:

- *For the 7-day calibration error test, either elemental Hg standards or a NIST-traceable source of oxidized Hg (referred to as "$HgCl_2$ standards"in the SNPR) may be used;*
- *Quarterly 3-level "system integrity checks" (which were called "converter checks" in the SNPR) using a NIST-traceable source of oxidized Hg may be performed in lieu of the quarterly linearity checks with elemental Hg;*
- *Daily calibration error checks may be performed using either elemental Hg standards or a NIST-traceable source of oxidized Hg. The daily performance specification has been made the same as for the 7-day calibration error test;*
- *The monthly converter check at three points has been replaced with a weekly system integrity check at a single point, and the weekly test is not required if daily calibrations are performed with a NIST-traceable source of oxidized Hg.*
- *When the Ontario-Hydro Method is used, paired trains are required, the results must agree within 10 percent RD, and the results should be averaged.*

Note that EPA plans to analyze RATA data from Hg monitors and may initiate a future rulemaking to adjust the relative accuracy performance specifications and to propose a performance-based RATA incentive system similar to the reduced frequency incentive system in 40 CFR part 75 for SO_2, NO_x, CO_2, and flow monitors.

EPA disagrees with the commenters who stated that there is no data available to justify

the proposed performance specifications for Hg monitors. Such data have been collected from several field test sites and for several different types of Hg concentration monitors, which show that Hg CEMS can meet the proposed calibration error and linearity standards, and can meet a 20 percent RA standard. Therefore, except for the daily calibration error specification, which has been tightened based on the available data, the final rule promulgates the proposed calibration error, linearity check, and RATA performance specifications, as proposed.

EPA has retained the requirement to check the converter periodically with $HgCl_2$ standards, because it is essential to ensure that all of the vapor phase Hg is being measured. The frequency of the check (which is referred to as a "system integrity check"in the final rule) has been increased from monthly to weekly, based on supportive comments to check the entire system more often, but the requirement to perform a 3-point check has been reduced to a single-point test. And the weekly test is not required if a NIST-traceable oxidized Hg source is used for daily calibrations.

There are several different devices available that can provide oxidized Hg, including the HOVACAL and the MerCAL. The HOVACAL has been successfully applied in the laboratory and field to generate and deliver known concentrations of $HgCl_2$ to Hg CEMS to achieve the requirements of the 40 CFR part 75 system integrity check. Moreover, oxidized Hg gas standards such as are produced by the HOVACAL and MerCAL are currently scheduled to be independently tested by NIST, to verify their suitability as reference gas standards.

Comment:

Commenter OAR-2002-0056-2922 stated that the requirement of proposed Appendix A, section 2.2.3 cannot be met. The commenter is not aware of any device, other than the Hovacal that might be able to deliver "known concentrations of $HgCl_2$" as required. The performance of the Hovacal does not appear to be well documented.

Response:

Several different sources of gaseous, oxidized Hg are available and have been demonstrated, incuding the HOVACAL. The HOVACAL has been successfully applied in the laboratory and field to generate and deliver known concentrations of $HgCl_2$ to Hg CEMS to achieve the requirements of the converter check as called for in the 40 CFR part 75 Hg CEMS precertification requirement. Moreover, oxidized Hg gas standards such as the HOVACAL and MerCAL are currently scheduled to be independently tested by NIST to verify their suitability as reference gas standards.

Comment:

Commenter OAR-2002-0056-2922 stated that in Appendix A, section 3.1, the specification should read "5% of the span value if the span value is 20 micrograms/dscm or greater, or 1 microgram/dscm if the span value is less than 20 micrograms/dscm." The

specification as now written penalizes any monitor with a span value between 10 and 20 micrograms/dscm.

Response:

Appendix A, section 2.1.7.3 defines span for Hg CEMS in multiples of 10 micrograms/dscm. Therefore, there will be no Hg span values between 10 and 20 micrograms/dscm. Appendix A, Section 3.1 is retained, as proposed, in the final rule.

Comment:

Commenter OAR-2002-0056-2922 stated that Equation F-29 appears to make the calculation correctly. However, the description in section 9.1.2 is difficult to understand. A complete set of equations and nomenclature should be provided instead of the cross references and replacement values.

Response:

Proposed Equation F-29 applies only to Hg-diluent monitoring systems. In the final rule, EPA has deleted Equation F-29 and all provisions related to this type of monitoring system. The final rule requires Hg mass emissions to be determined as the product of the Hg concentration and the stack gas flow rate.

Comment:

Commenter OAR-2002-0056-2922 stated that, both PS 12A and Method 324 are designed to measure vapor-phase Hg. Consistent with that, EPA should make clear in the 40 CFR part 75 RATA requirements (as EPA did in PS 12A, section 8.6.2) that the filterable portion of the reference method sample is not included when making the comparison to the CEMS. Consistent with that change, EPA should also remove the requirements in sectioin 75.59(a)(7) to record and report RATA results related to particle bound Hg, or justify the collection and submission of that additional data.

Response:

The final rule clearly states in 40 CFR 75.22 that only the vapor phase Hg, and not the filterable portion of the reference method sample is included when making the comparison to the CEMS. However, EPA has retained in section 75.59(a)(7) the recording and reporting of both gaseous and particle-bound Hg, when particle-bound Hg is provided by the reference method. The particle-bound Hg emissions data is required in today's final rule to provide information to assess the need for possible future regulation of particle-bound Hg.

6.5 MERCURY MONITOR AVAILABILITY

Comment:

One commenter (OAR-2002-0056-3560) stated that no correlation has been established between the basis for the standards and the required test methods. Plants that submitted Hg data to the EPA used the Ontario-Hydro Method to calculate their Hg emissions. EPA then used these data, based on the Ontario-Hydro Method, to create the Hg standards. Whether the proposed monitoring systems are comparable to the Ontario-Hydro Method, which was used to set the Hg emissions limits is unknown. If they are not, the Hg emissions limits could result in a standard that is not obtainable from the outset. This would leave facilities open to notices of violations/penalties when their failure to comply is a result of an inconsistency between analytical methods–the Ontario-Hydro Method used to set the Hg emissions limits versus Hg CEMS, sorbent trap monitoring systems, and long-term sampling monitoring that are to be employed to determine if units are meeting the emissions limits for compliance purposes. Discerning whether the test methodology utilized to create the Hg emission standards (Ontario-Hydro Method) correlates to any of the required test methods, and especially when Hg CEMS are not yet commercially available, is impossible.

Response:

EPA disagrees and believes Hg CEMS and sorbent trap monitoring systems have been demonstrated to be reasonably comparable to the Ontario-Hydro Method through various field demonstrations.

Comment:

One commenter (OAR-2002-0056-1854) noted that the analyzer can be no more than 100 feet from the sample probe. The commenter state that this means, in their case, that QA and maintenance procedures must take place on the stack platforms where personnel will be exposed to extreme weather conditions from time to time. The commenter also stated that their experience would also indicate that additional staffing by specially trained personnel will be required because these monitors cannot be left unattended for long periods of time.

Response:

Mercury CEMS demonstration testing conducted by EPA so far has provided evidence from a number of CEMS at a number of different utilities that the analyzer does not have to be located on the stack platform. Regarding on-going system maintenance, the level required will ultimately depend on the monitoring system and the emission characteristics. We have noticed a marked improvement in amount of time needed for hands-on monitor attendance over the time frame of demonstrations, including automation of daily check procedures and capability for remote system adjustment, and expect significantly more improvement in the coming months.

Comment:

One commenter (OAR-2002-0056-3548) stated concerns about the technical feasibility of operating and maintaining CEMS for Hg. The proposed monitoring requirements are beyond the capabilities of current monitoring equipment. Although the technology is developing rapidly, the proposed technology is analogous to EPA proposing to require 40 CFR part 75 monitoring requirements for flow, SO_2, and NO_x in 1970 with a compliance deadline of 1974. This being the case, it is imperative that EPA provide as much flexibility as possible in allowable monitoring methods.

Response:

EPA believes that Hg CEMS and sorbent trap monitoring systems meet the proposed monitoring requirements. The final rule contains flexibility by allowing sources to account for their Hg emissions by using Hg CEMS, sorbent trap monitoring systems (or a combination thereof), and, in some cases, using low mass provisions.

Comment:

One commenter (OAR-2002-0056-2915) stated concerns about the technical feasibility of operating and maintaining CEMS for Hg. The commenter's concerns regard the precision, reliability, and accuracy of the monitoring alternatives identified by the EPA in the proposed Hg rule. One area of major concern involves the proposed detection limits. The commenter asserts that as the allowable Hg emissions levels grow smaller (particularly in the case of new or well-controlled existing units), it becomes technically more difficult to measure Hg levels in the emissions from an electric generating unit (EGU) and to determine how the inherent measurement uncertainties will impact an EGU's compliance demonstration with the Hg limits. Further, should CEMS for Hg be required by the Hg rule, the commenter would have concerns with the proposed RATA process, particularly the length of time and amount of money that may be required to comply with the Hg monitoring requirements on an annual basis. The commenter asserts that the final monitoring requirements must be technically achievable and capable of measuring Hg emissions with precision, reliability, and accuracy in a cost-effective manner.

Response:

EPA believes that Hg CEMS will provide adequate precision, reliability, and accuracy for emissions trading, however, may not be necessary for all units. Consistent with the low mass emissions (LME) provisions for SO_2 and NO_x, the final rule provides a less rigorous monitoring option for low Hg emitters.

Comment:

One commenter (OAR-2002-0056-2830) stated it is not appropriate to require CEMS monitors on new units if operations begins more than six months after publication of the final

rule. CEMS have not been commercially demonstrated, and as commented on earlier, the commenter believes that they cannot be commercially demonstrated within 4 years of the rule being finalized.

Response:

EPA disagrees with commenter and believes that Hg CEMS and sorbent trap monitoring systems can be commercially demonstrated before rule implementation. However, the requirement for new units to use Hg CEMS has been withdrawn. New units may use sorbent trap monitoring systems instead, under both 40 CFR part 75, subpart I, and under 40 CFR part 60, subpart Da.

Comment:

One commenter (OAR-2002-0056-2429) requested the EPA provide additional technical information on both CEMS that meet PS12 requirements and sorbent traps that meet Method 324 requirements for various plant configurations and conditions such as wet stacks. Their units are equipped with wet scrubbers, fabric filters, and low NO_x burners.

Response:

EPA will provide additional information when available.

Comment:

One commenter (OAR-2002-0056-2899) stated that currently no Hg CEMS have been demonstrated to be accurate and reliable. The commenter stated that although continuous systems are available from different manufactures none have been used in continuous operation for an extended period of time. The commenter asserts that most have been used in pilot or short term full scale tests and generally compared to the Ontario-Hydro impinger method, which is a short term test ranging from minutes to hours, and this gives only snapshots of the continuous monitors performance. The commenter noted the current generation of continuous monitors are based on wet chemistry requiring almost constant maintenance and calibration. The commenter stated that although dry chemistry systems are under development and testing none are yet commercially viable. According to the commenter, at present continuous Hg monitors not are ready to be used for continuous compliance. The commenter stated that the EPA should allow the option of using a periodic measurement system such as EPRI's QuickSEM or other system instead of a continuous monitor for compliance with this rule.

Response:

EPA disagrees with the commenter and believes that field tests have demonstrated Hg CEMS to be accurate and reliable. The Hg CEMS have performed adequately for several months and meet the Ontario-Hydro Reference Method specifications. Furthermore, several dry

chemistry Hg CEMS are currently being tested at sites that represent the most challenging conditions and the Agency plans to share with industry the results of such experiences to facilitate the selection of appropriate monitoring methodology. EPA is also confident that substantial advancement of Hg CEMS will occur before the implementation of the rule and as other monitoring techniques may become available, is allowing the use of systems that can meet performance-based specifications.

Comment:

One commenter (OAR-2002-0056-5495) stated that CEMS for measuring low Hg emissions from waste coal is not a proven technology.

Response:

EPA disagrees with the commenter and believes that field tests have demonstrated Hg CEMS to be accurate and reliable at low Hg concentrations. The Hg CEMS have performed adequately for several months and meet the Ontario-Hydro Reference Method RATA specifications at two low Hg concentration (0.5 - 2 μg/dscm) coal-fired sources. EPA is also confident that substantial advancement of Hg CEMS will occur before the implementation of the rule and as other monitoring techniques may become available, is allowing the use of systems that can meet performance-based specifications.

Comment:

One commenter (OAR-2002-0056-2830) agreed with the EPA that compliance be monitored through the use of CEMS or other continuous measurement methods (e.g., sorbent trap) for all affected sources. However, the commenter is concerned that monitoring and recording technology has not evolved to the level of reliability necessary to collect emissions data for compliance purposes. As entered in the EPA Docket, the EPA-funded project termed "Long-Term Evaluation of Mercury Continuous Emission Monitoring Systems" - December 11, 2003, it was determined that the current capabilities of Hg CEMS are not at a level that can be relied on in a regulatory compliance environment. In almost all cases, the analyzers failed to meet the 20 percent relative accuracy criteria for the first two phases. In Phase III, there were some instruments that passed the relative accuracy criteria. The Carbon Bed technology was only tested in Phase ill of the program and did exceptionally well as compared to the other CEM systems and against the Ontario-Hydro Method. However, there are concerns that the facility was an "optimum test site." A substantial test for Hg analyzer systems should come under test conditions that are strenuous and challenging in order to identify shortcomings of the systems. The test should be completed at a facility where the sampling location has a representative particulate loading and sulfur concentrations. The systems should also be challenged under wet stack conditions.

Response:

EPA is currently field testing Hg CEMS and sorbent trap monitoring systems under strenuous and challenging conditions where the sampling location is under wet stack conditions and has a representative particulate loading and sulfur concentration. Preliminary data from these field tests seems to indicate that monitoring and recording technology are getting closer to the level of reliability necessary to collect emissions data for compliance purposes, supporting the Agency's confidence that by the end of the demonstration technology will provide the answers to the challenges presented.

Comment:

One commenter (OAR-2002-0056-3469) stated that lack of control and monitoring technology impedes speedy compliance. The EPA's proposed Hg monitoring technologies (e.g., CEMS 12A and Method 324) are not yet commercially available and do not yet provide accurate data. It is not known when they will be successfully tested and commercially available.

Response:

EPA disagrees with commenter; Hg CEMS and sorbent trap monitoring systems are commercially available and provide accurate data, as demonstrated by various completed and ongoing field tests. In addition, EPA believes these technologies will significantly advance before compliance is necessary.

Comment:

Is it currently feasible, or will it be feasible within the compliance timeframes of the proposed rule, to accurately monitor a source's Hg emissions by species?

Response:

The final rule requires the measurement of total vapor phase Hg, but does not require separate monitoring of speciated Hg emissions (i.e., elemental and ionized Hg). Because of the potential impact of Hg speciation on local versus broader geographical deposition, the Agency considers separate monitoring of these emissions as a need to be addressed. However, at least two current monitoring technologies can accurately monitor speciated Hg emissions. The Agency will continue to test speciated Hg monitoring technologies. If these technologies are adequately demonstrated, the Agency may consider a proposed rulemaking within four to five years after program implementation, which should provide enough lead time for development and installation of these monitoring systems.

6.6 MERCURY DILUENT SYSTEMS

Comment:

One commenter (OAR-2002-0056-3455), in reference to section 72.2 - Definitions, page 12453, asked why the proposed Hg emissions units of measurement are the same as NO_x - diluent? The Hg concentration measurements are orders of magnitude below NO_x emissions, thus applying a diluent correction with the additional uncertainties of measurement further complicates the direct emissions reporting uncertainties. Mercury is a resident pollutant in the fuel, it can be measured, and measurement should parallel the same regulation requirements as SO_2.

Response:

The final rule removes all mention of Hg-diluent monitoring systems and requires the hourly Hg mass emissions to be calculated in the same manner as is done for SO_2 under the Acid Rain Program, i.e., as the product of the Hg concentration and the stack gas flow rate. The final rule also better accommodates Hg analyzers that measure on a wet basis.

EPA believes that the rule can be considerably simplified and shortened without losing any flexibility by deleting the provisions related to Hg-diluent monitoring systems and allowing only Hg concentration monitoring systems and sorbent trap systems to be used. Therefore, the final rule removes all mention of Hg-diluent monitoring systems and requires the hourly Hg mass emissions to be calculated in the same manner as is done for SO_2, i.e., as the product of the Hg concentration and the stack gas flow rate.

6.7 LOW EMITTING UNITS

Comment:

One commenter (OAR-2002-0056-2900) questioned the need for continuous monitoring if the EPA requires coal-fired EGUs to meet MACT standards. The commenter urges the Agency to allow periodic monitoring and parametric monitoring approaches rather than restricting sources to the use of Hg CEMS or sorbent trap monitoring.

Response:

The Agency has decided to use a cap-and-trade program to control Hg emissions. Complete and accurate accounting of Hg emissions is required for a credible cap and trade program. Therefore, Hg CEMS or sorbent traps are required in the final rule. However, qualifying, low emitting sources may comply with today's monitoring requirements by using conservative default Hg emission factors and annual or semi-annual stack testing.

Comment:

Numerous commenters (OAR-2002-0056-2101, -2162, -2267, -2634, -2718, -2861, -2867, -2900-2918, -2922, -3432, -3509, -3513, -3565, -2855) requested that EPA provide a less rigorous, cost-effective monitoring option for low emitting units. Affected units could meet a low-emitter criterion based on a combination of unit size, operating time, and/or control device operation. Any marginal decrease in accuracy from less rigorous monitoring would have a minimal impact overall, because these units represent only a small percentage of the nationwide Hg mass emissions.

Response:

Consistent with the low mass emissions (LME) provisions in section 75.19 for SO_2 and NO_x, sections 75.81(b) through (g) of the final rule provide a less rigorous monitoring option for low Hg emitters. These provisions allow sources with estimated annual emissions of 29 lb/yr (464 oz/yr) or less, representing about 5 percent of the nationwide Hg mass emissions, to use periodic emission testing to quantify their Hg emissions, rather than continuously monitoring the Hg concentration. For units with Hg emissions of 9 lb/yr (144 oz/yr) or less, annual emission testing is required. For units with Hg emissions greater than 144 oz/yr but less than or equal to 464 oz/yr, semiannual testing is required. For reporting purposes, the owner or operator is required to use either the highest Hg concentration from the most recent emission testing or 0.50 μg/scm, whichever is greater. If, at the end of a particular calendar year, the reported annual Hg mass emissions for a unit exceed 464 ounces, the unit is disqualified as a low mass emitter and the owner or operator must install and certify a Hg CEMS or sorbent trap monitoring system within180 days of the end of that year. The final rule also contains special low mass emitter provisions for common stack and multiple stack exhaust configurations.

The Agency believes that a low mass emitter provision can be beneficial to both EPA and industry. It is cost-effective for industry, in that it allows periodic stack testing to be used to estimate Hg emissions instead of requiring continuous emission monitoring. In the context of a cap and trade program, a low emitter provision can provide environmental benefit, because it requires conservatively high default emission factors to be used for reporting~~, thereby removing Hg allowances from circulation~~. Also, allowing a subset of the affected units to use less rigorous monitoring reduces the administrative burden of program implementation, allowing EPA to focus its attention on the higher-emitting sources.

Selecting an appropriate low emitter cutoff point is of critical importance. On the one hand, if the cutoff point is too low (i.e., too exclusive) this would not be cost-effective for the regulated sources and would greatly increase the burden on the regulatory agencies to implement and maintain the program. On the other hand, if the cutoff point is too high (i.e., too inclusive), this would create inequities in the trading market.

Over the years, EPA has used a de minimis concept to either exempt low-emitting sources from monitoring or to allow these sources to use less rigorous, lower cost techniques to

monitor emissions instead of installing CEMS:

- *In the preamble of the 1993 Acid Rain Program (ARP) final rule (see 58 FR 3593, January 11, 1993), EPA's Acid Rain Division (now the Clean Air Markets Division) first used the de minimis concept to exempt certain new utility units from the Acid Rain Program (i.e., units less than or equal to 25 MW that burn only fuels with a sulfur content less than or equal to 0.05 percent by weight);*
- *EPA also allows gas-fired and oil-fired peaking units to use the less costly methodology in 40 CFR part 74, appendix E, to estimate NO_x emissions instead of using CEMS, because the Agency's analyses indicated that projected NO_x emissions from these units represent less than 1 percent of the total NO_x emissions from Acid Rain Program units.*
- *In 1998, EPA promulgated LME provisions in section 75.19 for SO_2 and NO_x (see 63 FR 57484, October 27, 1998). These provisions require the use of conservatively high default emission rates to quantify SO_2 and NO_x emissions. EPA determined the appropriate SO_2 and NO_x mass emissions thresholds or "cutoff points" for unit to qualify as a low mass emissions methodology, considering inventory and regulatory changes that had taken place since the original1993 Acid Rain rulemaking. The selected threshold values were based on a de minimis concept, i.e., the SO_2 and NO_x emissions from the units that could potentially qualify to use the LME methodology represented less than or equal to 1 percent of the emissions from all affected units.*

In 1999, EPA obtained Hg mass emissions estimates for the 1,120 utility units affected by the SNPR, as the result of an information collection request (ICR) that appeared in the Federal Register on April 9, 1998. These data show that if a low Hg mass emission threshold of 9 lb/yr were selected, 228 units, representing 1 percent of the total annual Hg emissions from coal-fired electric utility units in the U.S., could potentially qualify to use the low emitter option. However, EPA's analysis also indicated that by raising the cutoff point to 29 lb/yr, almost twice the number of units (435), representing just 5 percent of the total annual Hg emissions, could potentially qualify as low emitters. Therefore, EPA has decided to adopt the 29 lb/yr as the qualifying low mass emission threshold for Hg.

Although the 5 percent threshold represents a departure from the traditional de minimis value of 1 percent, the Agency believes that allowing units with Hg emissions of 29 lbs/yr or less to use the low mass emitter option is a better choice, for both economic and environmental reasons. For continuous monitoring methodologies, the annualized cost per unit will be about $89,500 for testing, maintenance, and operation. For sorbent trap methodologies, the annualized cost per unit will be about $113,000 for testing, maintenance, and operation. For a unit that emits between 9 lb/yr and 29 lb/yr of Hg, if the owner or operator elects to use the low emitter option, today's rule would require two stack tests per year (at $5,500 each), and an estimated $1,500 annual cost for technical calculation, labor, and other associated costs, for a total annual expenditure per unit of around $12,500. Therefore, for the approximately 207 units with Hg mass emissions between 9 and 29 lb/yr, the potential savings associated with the

*implementation of the low emitter option could be as high as: $89,500 - $12,500 = $77,000 * 207 units = $15,939,000 per year if LME is used instead of Hg CEMS. Alternatively, if LME is used instead of sorbent traps, the potential savings could be even higher: $113,000 - $12,500 = $100,500 * 207 units = $20,803,500 per year. This is achieved without losing the environmental integrity of the program or compromising the cap, because the default Hg concentration values used for reporting are conservatively high, and for units with flue gas desulfurization (FGD) systems or add-on Hg emission controls, the rule requires the maximum potential concentration (MPC) to be reported when the controls are not operating properly.*

As a further justification of the 5 percent low emitter threshold for Hg, EPA notes that there are two important differences between the Hg low mass emission provisions in section 75.81 and the LME provisions in section 75.19 for SO_2 and NO_x (which are based on a 1 percent threshold). First, under section 75.19, default emission rates are used exclusively, and there is no real-time continuous monitoring of the SO_2 or NO_x emissions. However, under section 75.81, the stack gas volumetric flow rate, which is used in the hourly Hg mass emission calculations, is continuously monitored. Second, the LME provisions in section 75.19 allow you to either use generic default NO_x emission rates without performing any emission testing, or, if you test for NO_x, you are only required to determine a new default emission rate once every 5 years. Under section 75.81, emission testing is required initially to qualify as a low emitter, and retesting is required either semiannually or annually thereafter, depending on the annual emission level.

6.8 RECORDKEEPING/REPORTING REQUIREMENTS

Comment:

One commenter (OAR-2002-0056-3455) stated that, in reference to Appendix A to the Preamble--Proposed Changes to Parts 72 and 75, (Proposed Rules March 16, 2004); page 12420 (Calculation of Mercury Mass Emissions) all of the calculations for both CEMS and sorbent methods contain a significant error. Rounding procedures for equation F-28 (hourly emissions) require rounding of hourly emissions, in ounces, to one decimal place. This would result in all but the largest sources registering as 0.0 oz/hr. Final rounding for reporting purposes may be to two or three significant figures. Intermediate results that are used in subsequent calculations should not be rounded to minimize propagation of numerical errors. For example, if hourly emissions for a particular unit were constant and calculated as 0.35 oz/hr, rounding to 0.40 oz/hr would result in excess emissions of 438 oz/year. Introducing artificial arithmetic artefacts into the emission calculations of a high value pollutant such as Hg is unwise and unnecessary.

Response:

EPA agrees with the commenter and has required in the final rule that equation F-28 results and the recordkeeping/reporting of hourly Hg mass emissions be rounded to the nearest thousandth of an ounce. EPA's 40 CFR part 75 policy is that intermediate results that are not reported, but are used in subsequent hourly calculations should not be rounded to minimize

propagation of numerical errors.

Comment:

One commenter (OAR-2002-0056-3455) stated that, in reference to Appendix F to the Preamble--Proposed Changes to Parts 75, (Proposed Rules March 16, 2004); page 12472, the calculation procedure in Appendix F to Part 75 – Conversion Procedures contains serious errors. In particular, equation F-28 is erroneous and does not yield correct results. The commenter noted that the Hg concentrations used for mass determination are not referenced to any specific CO_2 or O_2 levels. This provides further support for the position that reporting on this basis is superfluous.

Response:

EPA has corrected equation F-28 in the final rule. The final rule does not reference Hg concentrations to any specific CO_2 or O_2 levels.

Comment:

One commenter (OAR-2002-0056-3455) noted that, in reference to Appendix F to the Preamble--Proposed Changes to Parts 75, (Proposed Rules March 16, 2004); page 12472, Equation F-28 contradicts Equation 3 (FR page 4724) by requiring hourly averaging of the Hg concentrations and hourly totals of the stack flow before performing a calculation. Significant flow and concentrations can take place over the course of an hour, resulting in an erroneous calculation. This form of calculation may be appropriate for the sorbent method. However, for CEMS, a more accurate and unbiased calculation is available by multiplying concentration and volumetric readings together at the data rate of the CEMS and then summing to produce hourly emissions.

Response:

EPA understands the concern of the commenter. However, because one hour periods are the basic Hg emissions reporting increment, EPA requires sources to calculate their quarterly and annual Hg mass emissions using hourly quantities. This allows EPA to recalculate quarterly and annual Hg mass emissions using the same reported hourly numbers that sources use. If sources used sub-hourly increments to calculate mass emissions, EPA's recalculated mass emissions based on reported hourly values would not agree with the reported numbers.

Comment:

One commenter (OAR-2002-0056-2889), although not supporting Hg trading, did support using the electronic reporting, under the acid rain program emission reporting system, set up for SO_2 and NO_x for Hg emissions reporting. This would consolidate the emission reporting requirements under the NSPS and Acid Rain Program, which regulate the same

facilities. The addition of Hg to those pollutants already reported to the Clean Air Markets Division would benefit EPA, States, public, the industry.

Response:

The final rule requires the same type of electronic reporting that is used under the Acid Rain and NO_x Budget Programs.

6.9 OTHER

Comment:

One commenter (OAR-2002-0056-3200) supports EPA's rolling 12-month averaging calculation for compliance determinations. Mercury is not an acute health hazard and concerns arise from long-term chronic exposure. Thus, Hg control lends itself well to a compliance program with long-term averaging.

Response:

The Agency has decided to use a cap-and-trade approach to control Hg emissions. However, note that the proposed NSPS for Hg has been finalized under 40 CFR 60, subpart Da, and compliance with the Hg emission limit in 40 CFR 60.45a is determined on a 12-month rolling average basis.

Comment:

Two commenters (OAR-2002-0056-2068, -2422) stated that EPA's proposed methods for measuring Hg emissions from coal fueled power plants must address the detection limits of those methods and how those detection limits will impact compliance demonstrations with the new source MACT limits. The EPA must take into account the ability of existing technology to detect Hg emissions at such minute levels, and must also discuss the range of test results which may be allowable over time. Without such clarification, units will be unable to reliably determine if their test results are within an acceptable range of compliance, or if they violate the limits. One commenter (OAR-2002-0056-2422) adds that regardless of the monitoring alternatives specified by EPA, the final rule must address the detection limits of that testing methods). As the allowable Hg emission levels grow smaller, it becomes scientifically more difficult to assess whether the emission limits are being met.

Response:

In field tests of Hg monitoring methodologies, EPA has observed that low concentrations of Hg can be detected and accurately measured with the currently-available monitoring systems. Mercury compliance will be determined under a cap-and-trade program, rather than MACT.

Comment:

One commenter (OAR-2002-0056-3439) stated that the proposed supplemental rule (dated March 16, 2004) defines the minimum acceptable test run duration for the reference test method (Ontario-Hydro) as 2 hours. Given the very low concentration of Hg in the gas stream, the commenter recommended a test run of longer duration or sufficient analysis of available test data be conducted to provide adequate confidence in the 2 hour minimum test run duration.

Response:

EPA has data to indicate that 2 hours is sufficient for application to controlled sources. However, in the final rule, the 2-hour minimum RATA run length provision has been withdrawn. For the RATA of a Hg CEMS using the Ontario-Hydro method, or for the RATA of a sorbent trap system (irrespective of the reference method used), the final rule simply specifies that the minimum time per run must be long enough to collect a sufficient mass of Hg to analyze.

Comment:

One commenter (OAR-2002-0056-2063) recommended with regard to QA/QC requirements that annual RATA tests using a Reference Method, either wet chemistry-based or Method 324 (paired trains) are appropriate for either a CEM or Method 324.

Response:

EPA agrees with the commenter with the exception that we do not consider that sorbent trap monitoring procedure has the quality to serve as a reference method. We are, however, confident of its performance as a monitoring method as long as a yearly RATA is performed and passed and the performance criteria in Appendix K are met.

Comment:

One commenter (OAR-2002-0056-2883) believed that the EPA should hold workshops to assist both purchasers, States, and vendors on various monitoring systems.

Response:

EPA agrees with the commenter and will provide workshops to assist both purchasers, States, and vendors on any issues related to the final rule.

Comment:

One commenter (OAR-2002-0056-2889) stated that the proposed PS-12A only accounts for vapor phase Hg emissions. This allows facilities to ignore particulate-bound Hg emissions when using a CEMS. The State of Massachusetts provided test data to showed that particulate-

bound Hg can constitute as much as 40 percent of total Hg. The commenter urged EPA to require total Hg emissions as the basis of compliance demonstrations per their state rules.

Response:

Nationwide, 97 percent of Hg emissions from the outlets of coal-fired utilities are vapor phase. Currently there is no established technology, other than the Ontario-Hydro Method to measure particulate-bound Hg. Therefore, today's final rule only regulates vapor phase Hg emissions.

Comment:

One commenter (OAR-2002-0056-2867) stated that for applications where Hg CEMS are used and for Hg monitoring and audits to be advanced, the commenter submits a real time instrumental reference method for RA audits is needed. The commenter stated that EPA must develop such an instrumental reference method for Hg.

Response:

EPA agrees with the commenter. Based on field testing, EPA intends to develop an instrumental reference method for Hg. Initial evaluations of such a method have already begun.

Comment:

One commenter (OAR-2002-0056-1842) stated that monitoring Hg to the degree of accuracy required for trading ($35,000/lb) is a daunting task. Add to this the fact that EPA has not addressed particulate Hg and suggested just ignoring this quantity. The rationale is that particulate Hg is only three percent of the total. At $35,000/lb the ignored quantity translates into $105,000 for a 300 MW boiler, $1,050,000/yr for a 3,000 MW plant and $105,000,000 for the whole industry. Mercury measurement is money measurement. This number may even be larger. Fine particulate emissions from power plants are not measured. The commenter believed emissions are much larger than EPA estimates. Therefore particulate Hg emissions from plants with old inefficient precipitators are likely to be much higher than emissions from the average plant. Also some Hg control technologies create particulate Hg. The RJM concept is to condense acid mist on fine particulate in order to create acid deposition sites. Under the EPA scheme all the Hg could then be discharged and not counted. Also there is a 10 times differential between fine particulate emissions from old precipitators and new ones. This means it will be necessary to measure particulate Hg. Periodic Method 5 sampling will result in filter catches which can then be analyzed for particulate Hg. The accuracy will be a function of the sampling interval and the variations from sample to sample. A few stack tests per year may establish particulate Hg plus or minus 50 percent. A stack test each week would reduce the inaccuracy to some smaller range e.g., 10 percent. However continuous method 5 sampling would improve accuracy even more. Annual Hg quantities then will be the integration of the results from sorbent traps, Hg CEMS, method 5 tests for particulate Hg and material balances involving the

amounts in the coal, ash, fly ash, and wastewater.

Response:

Nationwide, 97 percent of Hg emissions from the outlets of coal-fired utilities are vapor phase. Currently there is no established technology, other than the Ontario-Hydro Method to measure particulate-bound Hg. Therefore, the final rule only regulates vapor-phase Hg emissions. EPA will collect the particulate Hg concentrations from any source using a reference method capable of providing particulate Hg concentrations and may initiate a future rulemaking to require that these emissions be monitored and reported.

Comment:

Several commenters (OAR-2002-0056-2634, -2718, -2861, -2922, -3565) noted that proposed 40 CFR 75 subpart Da section 60.50a(j) would require Hg CEMS and sorbent trap systems to perform some QA/QC requirements "in accordance with" Procedure 1 of 40 CFR part 60, Appendix F. This presents some issues for sorbent trap systems because Procedure 1 does not include all of the information necessary to perform those tests. In addition, with the use of 40 CFR part 60 QA/QC requirements in subpart Da, new units that are subject to both the NSPS and the cap-and-trade program would be subject to both the specified 40 CFR part 60, Appendix F, and the 40 CFR part 75, Appendix B, QA/QC requirements. EPA should avoid imposing these duplicative and inconsistent requirements by explicitly stating in the subpart Da revision that Hg CEMS and sorbent trap systems meeting the requirements of 40 CFR part 75 do not have to comply with 40 CFR part 60, Appendix F, procedures set out in 40 CFR 60.50a(j). EPA should use the subpart Da NO_x revision in 40 CFR 60.47(c)(2) as a model.

One commenter (OAR-2002-0056-3469) stated that to minimize duplication and additional costs, the EPA should adopt monitoring and reporting standards that are consistent with those for other air quality programs.

Response:

In the final rule for Hg (40 CFR 60, subpart Da), EPA has made it clear that the provisions of 40 CFR part 60, Appendix F do not apply to sorbent trap monitoring systems. Rather, sorbent trap monitoring systems must meet the applicable QA requirements in Appendices B and K of 40 CFR part 75. An annual RATA of each sorbent trap system is required, in addition to a number of system-specific QA tests and procedures. For the quality-assurance of data from Hg CEMS, the NSPS clearly states that sources subject to both 40 CFR 60, subpart Da and 40 CFR part 75, subpart I may implement the QA procedures in 40 CFR part 75, Appendix B in lieu of the procedures in 40 CFR part 60, Appendix F.

RESPONSE TO SIGNIFICANT PUBLIC COMMENTS ON THE PROPOSED CLEAN AIR MERCURY RULE

Received in response to:

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 4652; January 30, 2004)

Supplemental Notice for the Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 12398; March 16, 2004)

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources, Electric Utility Steam Generating Units: Notice of Data Availability
(69 FR 69864; December 1, 2004)

Docket Number OAR-2002-0056

7.0 IMPACT ESTIMATES

US Environmental Protection Agency
Emissions Standards Division
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

15 March 2005

General Outline

7.0 IMPACT ESTIMATES

7.1 IPM MODELING

Comment:

One commenter (OAR-2002-0056-2578) stated that both they and EPA have been employing Eulerian regional models for simulating both deposition patterns of Hg under current emissions, and how those deposition patterns might change under proposed utility Hg regulation. The commenter stated that there is strong evidence that those models tend to overestimate near-source ground-level concentrations and deposition of Hg when compared to equivalent calculations using Gaussian plume simulation local-scale models. The commenter stated that the consequences associated with this model precision include the following: 1) it helps explain why models tend to show higher deposition than is measured by Hg monitoring stations in some regions of the U.S., and 2) these overpredictions of deposition will tend to overestimate the assessments of how much Hg is entering various waterbodies, accumulating in fish and eventually resulting in a potential exposure to humans.

Response:

There is no evidence that in our applications of Eulerian regional models that they overestimate ground-level wet deposition of Hg. The models generally do not show higher wet deposition than the Hg monitoring sites. The Community Multiscale Air Quality (CMAQ) Model used for the Clean Air Mercury Rule (CAMR) underestimated annual Hg wet deposition at the majority of Mercury Deposition Network sites. There is not a measurement network for Hg dry depositions or Hg concentrations, so it cannot be concluded that the Eulerian regional models overpredict these values. In general, the Gaussian models do not have adequate atmospheric chemistry or deposition algorithms to predict Hg as well as the Eulerian regional models.

Comment:

One commenter (OAR-2002-0056-3454) stated that the current Hg control proposal made under the CAA, section 111 provisions would not create markets for technology development nor encourage innovation as the projected Hg cap level was set too high (i.e., at the revised co-benefit level). The commenter further stated that EPA's modeling analysis does not consider the low cost reductions that will come from enhancing existing control technologies for greater Hg capture. The commenter stated that these innovations will reduce the cost and overall demand for Hg-specific reductions. The commenter stated that EPA's projections for Hg-specific control installations under the Section 111 proposal estimate that only 1 GW, or approximately two of the more than 1000 coal-fired boilers in the U.S., would install Hg control technologies by 2010.

Response:

EPA has set the first phase cap of CAMR at a level that represents the Hg reductions

expected as co-benefits accompanying the SO_2 and NO_x caps under CAIR in 2010, of the combined emission reductions that SO_2 and NO_x controls provide in terms of reducing Hg emissions. The ability of sources to bank excess Hg allowances in the first phase of the program, as well as the lower second phase cap, will provide a strong incentive for the development of efficient and cost-effective Hg control technologies. In fact, developments in Hg control technologies, such as advanced sorbents, are already occurring. EPA's Office of Research and Development has a white paper (available in the docket) discussing the current state of Hg control technology development.

Comment:

One commenter (OAR-2002-0056-2578) stated that modeled predictions of when emissions would ultimately reach the 15 ton/yr Phase II cap in the proposed cap and trade rule are sensitive to model assumptions concerning co-benefits, control effectiveness, and other poorly determined variables. The commenter stated that EPA assumptions produce a longer phase-in period than the set of assumptions used by the commenter, considered more realistic based on research results. The commenter stated that differences in emissions banking behavior between their simulations and EPA's results are due to three factors (the commenter provided evidence supporting each of the following points): 1) EPA assumes larger Hg reductions from key SO_2 and NO_x controls ("co-benefits") than is the current technical consensus; 2) EPA's cost and effectiveness assumptions for removal of Hg using activated carbon injection are more pessimistic than those incorporated in the commenter's model, and; 3) Other EPA assumptions appear to cause the model to rely more on FGD retrofits over coal switching for units to achieve SO_2 targets than the commenter assumed. The commenter asserted that their simulations employ assumptions which their researchers view as more realistic and thus result in the 15 ton cap being met by 2020.

Response:

EPA agrees that projections of the timeline for achievement of the 15 ton second phase Hg cap are sensitive to modeling assumptions. EPA published a NODA discussing some of these assumptions and input the Agency received from commenters that conducted modeling of the Hg cap-and-trade program. EPA requested comment in the NODA on the following: projected improvements in variable operating costs for ACI over time, consideration of additional Hg control technology options, availability of ACI, Hg control technology costs, the impact of banking on achieving the second phase Hg cap, the level of co-benefit Hg reductions under CAIR, and Hg removal assumptions for the various technology combinations included in IPM. Assumptions in IPM are discussed in detail in the documentation for IPM v. 2.1.9, which is available in the docket. EPA's economic analysis of the final rule is discussed in Chapter 7 of the Regulatory Impacts Analysis (RIA). Regarding the modeling submitted by the commenter, EPA has noted that the projected emissions of 15 tons in 2020 appear to be an artifact of the grouping of the 2020 run year with the model end run year of 2040. EPA maintains that, in a least-cost solution model like the commenter's, the model would solve for the cap in the final run year grouping.

4 Comment:

One commenter (OAR-2002-0056-3552) disputed EPA's rationale for not using section 112 as a control strategy because of the anticipated absence of local or regional hot spots. The commenter stated that EPA based this position on the expected 70 percent emission reduction under the proposed section 111 rule and cap and trade program and that analyses of the Acid Rain program did not show any hot spots. The commenter stated that EPA should provide evidence to support this position, including a description of the models, assumptions, and default. The commenter asserted that states should have the opportunity to review the modeling runs used to determine local deposition and check input values such as default values, percent Hg in coal, control devices and their efficiencies, and Hg composition of the emissions released. The commenter stated that for such an important decision, the methodology EPA used to arrive at this prediction should be clear to the states.

Response:

EPA is finalizing a cap-and-trade program under section 111. All analysis of the rule is available in the RIA. Documentation of EPA's models and assumptions are available in the docket. EPA believes that the final rule will protect public health, as show in its analysis.

7.2 HEALTH

7.2.1 Mercury in Coal

Comment:

One commenter (OAR-2002-0056-3538) stated that the proposed rule downplays Hg health risks, retreats from previous findings, and exaggerates scientific uncertainties to justify a weak standard.

Response:

EPA disagrees with the comment. The U.S. is, for the first time, establishing Federal rules that will limit Hg emissions from coal-fired power plants. We are moving forward with a regulatory program that is unprecedented in the world and will address health risk resulting from coal-fired utility Hg emissions. As new scientific and health data become available, the standards provide for a reanalysis of the appropriateness of the level of the standard.

Comment:

One commenter (OAR-2002-0056-2929) stated that in EPA's December 2000 regulatory determination, EPA noted "there are uncertainties regarding the extent of the risks due to electric utility mercury emissions." The commenter stated that previously, in its Mercury Research Strategy, EPA stated that "[t]he amount of mercury deposited in the United States that can be directly attributed to domestic combustion sources remains uncertain." The commenter further

stated that three years later, after extensive research on the fate and transport and atmospheric chemistry of Hg, EPA stated in the proposed Hg rule that the agency "cannot currently quantify whether, and the extent to which, the adverse health effects occur in the populations surrounding these facilities, and the contribution, if any, of the facilities to those problems." The commenter further stated that, in addressing the state of the science, the proposed rule notes that "the relationship between Hg emission reductions from utility units and methylmercury concentrations in fish cannot be calculated in a quantitative manner with confidence." The commenter also stated that EPA admits that "[t]he Agency is unable to provide a monetized estimate of the benefits of Hg (mercury) and Ni (Nickel) emissions reduced by the proposed rule at this time." The commenter added that recent and comprehensive research undertaken by the Centers for Disease Control and Prevention (CDC), which measured Hg in the blood of women, indicates that people in the U.S. are not being exposed to levels of Hg considered to be harmful to fetuses, children, or adults. The commenter stated that according to the CDC, "The levels reported in this NHANES [National Health and Nutrition Examination Survey] 1999-2000 subsample for maternal-aged females were below levels associated with in utero effects on the fetus, or with effects in children and adults (National Academy of Sciences, 2000)." Another commenter (OAR-2002-0056-3440) added that health effects of Hg reductions from power plants have not been demonstrated.

Response:

As part of its analysis of the final rule, EPA has estimated the health benefits of reducing Hg from utilities. EPA's analysis focuses on the benefits of reducing neurological impacts of exposure to MeHg via consumption of self-caught freshwater fish. The RIA for this rule contains this analysis in Chapter 11.

Comment:

Many State Attorney Generals contended that EPA downplayed and mischaracterized the current science and technology concerning the public health impacts caused by Hg exposure, which supports the need for an appropriate MACT standard under section 112. Many U.S. Senators and one Congressman agreed that certain scientific evidence appears to have been changed to diminish the significance of health risks. One commenter stated that EPA disregarded the available science when evaluating the adverse health impacts of Hg exposure, ignored the degree to which the public is exposed to Hg, did not assess the benefits to public health of decreased MeHg ingestion in fish, and presented, without foundation, the global and local impacts of Hg deposition. The commenters contended that there is overwhelming evidence, including recent new data, that Hg emissions from U.S. powerplants are severely impacting inland and coastal waters, leading to massive environmental damage and the need for fish consumption advisories. The commenters stated that Hg emissions from U.S. powerplants are also contributing to adverse effects on human health. The commenters stated that the relationship between Hg emissions from coal-fired plants and the elevated levels of Hg in fish is not in dispute. The commenters added that there is sound scientific basis for requiring stringent controls for Hg emissions based on EPA's own statements. Further, the commenters stated that uncertainties that may exist point to the need for, not the weakening of, safeguards to reduce the

public's exposure to Hg. The commenters stated that in light of EPA's own findings that power plants are the largest emitters of Hg, the overwhelming evidence that 8 percent of women of childbearing age have elevated Hg levels, that over 600,000 babies are born overexposed to Hg in utero with potential neurological deficits, and the fact that fish consumption advisories nationwide are on the rise, EPA regulatory response should be to establish an appropriate plant by plant MACT standard under section 112 to achieve meaningful reductions of Hg emitted to the atmosphere.

Response:

Through this rulemaking and the separate CAIR rule, EPA is taking steps to lower the Hg emissions from utilities. As explained in the preamble to the final rule, EPA believes that the steps taken in these packages will provide a substantial positive step in reducing the health effects which may result from the release of Hg from these utilities.

As part of its analysis of the final rule, EPA has estimated the health benefits of reducing Hg from utilities. EPA's analysis focuses on the benefits of reducing neurological impacts of exposure to MeHg via consumption of self-caught freshwater fish. The RIA for this rule contains this analysis in Chapter 11.

Comment:

One commenter (OAR-2002-0056-3499) stated that EPA has underestimated and distorted the health effects caused by Hg from power plants. The commenter stated that the brief discussion of the potential cardiovascular effects of methylmercury (MeHg) concludes that the existing studies present conflicting results. The commenter asserted that this statement is not documented and is largely not the case. The commenter also noted that EPA identifies those at risk from MeHg as those who regularly and frequently consume large amounts of fish. The commenter asserted that this is not necessarily the case and misleading. The commenter stated that even moderate consumption of fish with high Hg concentrations can lead to significantly elevated Hg levels and health risk.

Response:

The science of documenting and estimating the health effects of exposure to low levels of Hg is evolving. EPA is aware that a study on potential cardiovascular effects has been recently entered into the docket to this rulemaking (February 22, 2005). EPA was not able to evaluate the results of this study in the determination for the final rule. EPA is aware of this effect and other effects of low level Hg exposures. Our RIA for this rulemaking lays out our understanding of the current state of the science and provides quantified or qualitative estimates of the effects of reducing Hg emissions from utilities.

7.3 ENVIRONMENTAL IMPACTS

Comment:

One commenter (OAR-2002-0056-2430) recommended that if EPA pursues regulation under section 111, it include some type of risk and environmental health assessment including an evaluation of the effects of Hg deposition. The commenter stated that although residual risk requirements under section 112 address risk to public health and the environment, section 111 does not. The commenter stated that the disassociation of CAA regulations from public health and the environment is unacceptable public policy and sets a bad precedent.

Response:

EPA has addressed the implications of the rule as suggested by the commenter.

7.4 COSTS AND ECONOMICS

Comment:

One commenter (OAR-2002-0056-3528) stated that most, if not all, small businesses will be impacted by a regulatory structure that imposes new requirements on Electric Utility Steam Generating Units (power plants). The commenter noted that small business owners need electricity to run their businesses, and it is certain that if and when a new regulatory scheme is implemented, the costs associated with it will be passed on to small firms in the form of higher electricity prices. The commenter stated that Dr. Willie Soon, a physicist at the Solar, Stellar, and Planetary Sciences Division of the Harvard-Smithsonian Center for Astrophysics and an astronomer at the Mount Wilson Observatory, has noted that "industrial demands for mercury (and hence emissions) in the U.S. have been systematically and rapidly decreasing over time through common sense public policy controls on Hg content in less essential products like paints, pesticides and batteries. From a regulatory-efficiency standpoint, the relatively clean U.S. power plants are not the best target for addressing the global mercurial emission problem. Why? We lack the technological know-how to eliminate Hg emissions... As such, the proposed regulations are likely to drive up energy costs significantly. Since the poor and middle class pay a greater percentage of their income on basic energy needs, the heaviest burden of such regulations will fall on those least able to afford them." The commenter submitted that indeed, an April 2003 report from the U.S. Department of Energy (DOE) declared that "technology to cost-effectively reduce mercury emissions from coal-fired plants is not yet commercially available." The commenter stated that one estimate placed the annual price tag of reducing Hg emissions from U.S. power plants at $3 billion. The commenter stated that the electric power industry provides a vital service to our nation and is a key driver of local and national economies. The commenter believed that while EPA might contend that, on average, the costs of the rule will be "low", even a seemingly small 5 to 10 percent increase in electricity costs will impact small businesses, low-income families and retiree households. The commenter believed that in the end, while it is highly unlikely that the EPA will abandon the proposed Hg emissions regulation, the Agency must present clear scientific justification for moving forward – that

regulating will create net significant human health benefits, especially if promulgated under the Clean Air Act. The commenter submitted that if the EPA moves forward, it cannot require too much too soon as would be the case under a maximum achievable control technology (MACT) requirement. The commenter noted that the 29 percent reduction target for 2007 is not scientifically feasible as noted above. The commenter believed that if reductions are pushed too quickly, this would endanger the use of cost-effective coal as a fuel and would put more pressure on already strained natural gas markets. The commenter stated that a variety of fuels is needed so that there is no run up in prices, such as has occurred recently for natural gas. The commenter noted that natural gas prices are very important for all consumers, including families, farmers, manufacturers and, of course, small businesses. If controls are required, and presented with the limited options under the proposed rule, the commenter viewed the cap-and-trade program as less restrictive and more cost-efficient than MACT. The commenter stated industry will not be forced to utilize expensive alternatives to coal, the nation's most abundant, affordable fuel source. The commenter noted that the cost increases for small businesses will not be as high (though any cost increase is burdensome to price sensitive small firms). Similar to the acid rain program, the commenter believed EPA should manage the new program by laying out the rules of the road but not dictate the path to the destination.

Response:

EPA is finalizing a cap-and-trade program for Hg emissions. One of the advantages of a cap-and-trade approach is that the ability for emissions reductions to be achieved more efficiently than a command and control approach. EPA projects that today's rule will have an impact on retail electricity prices of less than 1 percent. This analysis is discussed in Chapter 7 of the RIA. It should also be noted that EPA's modeling does not take into account advancements in pollution control technology and the cost reductions associated with these, such that EPA is likely overestimating the impacts of the final rule.

Comment:

One commenter (OAR-2002-0056-3556) stated that the costs of implementing this program are significant. The commenter supported the comments on implementation and compliance being supplied by UARG. The commenter stated that EPA's estimates are too low. The commenter stated that they are currently spending in excess of seven hundred million dollars to implement the NO_x SIP Call. The commenter stated that this number is more than a factor of 3 higher than their original estimate – which was higher than EPA's estimate. The commenter stated that the NO_x SIP call dealt with retrofitting existing units with known technologies. The commenter expected the costs of implementing the Hg rule to be higher, once the to-be-determined Hg-specific controls are included in the system. The commenter stated that many utilities, including the commenter, are facing the reality of obtaining adequate financing to cover the costs of implementation. The commenter stated that this is further complicated by the need to clearly layout a cost-recovery mechanism, within the current regulatory system in Michigan. The commenter strongly recommended that EPA use a more accurate methodology for projecting the costs of MACT, including characterizing each individual unit in the database, using site-specific conditions to determine which technology is the least cost option.

Response:

EPA is finalizing a cap-and-trade program for Hg under section 111 of the CAA, rather than a Hg MACT. This system allows for a variety of control technologies and provides incentives for achieving least-cost reductions. The projected impacts of the final CAMR are discussed in Section 7 of the RIA.

Comment:

One commenter (OAR-2002-0056-4191) stated that EPA must ensure that the Hg rule does not disadvantage coal, especially Gulf Coast lignite, because doing so would aggravate the already precarious natural gas supply and price situation. The commenter submitted that high natural gas prices are a significant economic challenge to business and industry, especially small businesses. The commenter added that high natural gas prices are undermining U.S. economic recovery, pushing jobs offshore in gas-dependent industries, and are increasing the cost of electricity in several regions of the U.S. The commenter pointed out that during the late 1990's, the historic surplus of natural gas disappeared due to a growing economy, governmental access restrictions to large gas deposits onshore and offshore, and clean air regulations that encouraged electric generators to use natural gas instead of coal. The commenter stated that by 2000, spot market prices soared and the average annual price for gas more than doubled. The commenter added that the industrial sector, unable to pass through costs to consumers, was hit hard. The commenter noted that U.S. natural gas production is not keeping pace with the demands of a growing population and a slowly recovering economy. The commenter believed that this crisis, brought on partly by national policies encouraging the use of natural gas while discouraging its domestic production, makes clear the need for the U.S. to maintain a diverse fuel supply and provide adequate domestic production of energy. The commenter submitted that if the Hg rule was to even slightly decrease the dependence on coal as a viable fuel for electric generation, the natural gas supply and the price problems would increase. The commenter stated that it is estimated that forced replacement of coal with natural gas as fuel in electric generation would increase the demand for natural gas by about 35 percent and would increase natural gas prices by about 33 percent. The commenter stated that EGUs designed to burn lignite cannot easily, quickly, or cheaply switch to burn other fuel types. The commenter noted that lignite's low heat content and its other properties call for a specific boiler design. The commenter claimed that, as such, lignite-fired EGUs would require significant alterations to allow them to burn non-lignite fuels. The commenter added that in addition to being time consuming, such alterations would be very expensive. The commenter stated further that companies that own and operate lignite-fired EGUs are often parties to long-term contracts to purchase the lignite. The commenter noted that, therefore, even if such EGUs could no longer burn lignite, they would still be required to purchase it pursuant to any such long-term contracts. The commenter added that moreover, Gulf Coast lignite-fired EGUs in Texas are "mine-mouth" plants, which means they are located on the property from which the lignite is mined. The commenter stated that therefore, for many such EGUs, rail lines to the EGUs that could be used to transport other types of fuel to the site would have to be constructed. The commenter asserted that for the foregoing reasons, the final rule must take into account the need to avoid any undue switching from coal, especially Gulf Coast lignite, to another type of coal or natural gas as fuel in electric generation.

Response:

The impacts of CAMR on coal production are discussed in Chapter 7 of the RIA. Coal-fired generation and natural gas-fired generation are projected to remain relatively unchanged because of the phased-in nature of CAMR, which allows industry the appropriate amount of time to install the necessary pollution controls. Additionally, no coal capacity is projected to be uneconomic to maintain under CAMR relative to the CAIR.

Comment:

Several commenters (OAR-2002-0056-2609, -2684, -3380) in Colorado believed the rule will have a negative economic impact on Aspen because continuation of high Hg emissions from coal-fired plants subsidizes coal which contributes to global warming and prevents a level playing field for developers of renewable energy sources.

Response:

Under this rulemaking, EPA is placing Hg emission reduction requirements on coal-fired electricity generating units that will require investment by the industry, and, thus, is not providing a subsidy to coal-fired generation.

Comment:

One commenter (OAR-2002-0056-2887) recommended that the capital costs and cost effectiveness of Hg controls be expressed in terms of costs to the ratepayer (e.g., mills/kWh of electricity). The commenter believed from this perspective, the costs are lower than those for NO_x control from electric utilities (which are considered to be cost effective by industry and state regulators and the basis for the "Section 110 transport SIP call" and the Clean Air Interstate Rule proposed concurrently with the MACT standard). According to the commenter, the total annual costs for Hg controls ranges from 0.18 to 1.15 mills/kWh compared to 0.21 to 0.83 for low-NO_x burners and 1.85 to 3.62 mills/kWh for selective catalytic reduction. The commenter contended that EPA's presentation of cost effectiveness in terms of dollars per pound of Hg removed by a control technology compared to the costs of controlling NO_x or SO_2 emissions from power plants is misleading because Hg is emitted in far small quantities than conventional pollutants. The commenter added that, however, Hg presents a far greater public health and environmental threat on an equivalent mass basis.

Response:

EPA discusses the projected impact of CAMR on retail electricity prices in Chapter 7 of the RIA. EPA believes that cost-effectiveness measures (e.g., $/ton) are useful tools to evaluate and compare marginal costs of various programs. EPA agrees that cost-effectiveness measures for different pollutants may not be meaningfully compared with each other. The benefits and costs of CAMR are discussed in detail in the RIA.

Comment:

One commenter (OAR-2002-0056-4177) believed EPA's economic analysis is inadequate and flawed. The commenter asserted that EPA used the wrong economic benchmark. The commenter stated that the economic cost of Hg control should not be assessed the same way as criteria pollutants because Hg creates public health problems at lower levels. The commenter stated that EPA should evaluate the costs in terms of the additional cost of electrical production rather than in cost/ton of pollutant removed. The commenter stated that using the other approach, the best Hg controls cost 0.18 to 1.15 mils/kWh. The commenter stated that given the added costs of litigation, health care, and special education for affected children, EPA would determine that a legally reasonable standard is economical.

Response:

EPA does evaluate the cost of Hg control in terms of the additional cost of electrical production. This analysis is presented in Chapter 7 of the RIA.

Comment:

One commenter (OAR-2002-0056-2819) did preliminary cost estimates for installing FGD or ACI on their coal-fired boilers using EPA methodology and compared their estimates to those from Public Service of New Hampshire, ADA-ES, and DOE. The commenter reported that the results are similar to NESCAUM estimates (see Mercury Emissions from Coal-Fired Power Plants: The Case for Regulatory Action, October 2003). The commenter reported that estimated capital costs for FGD range from $54.2-$100.4 million and for ACI range from $0.98 to $47.3 million depending on size and other factors. The commenter stated that while these costs may not be applicable to all units nationwide, they are sufficient to justify standards at least as stringent as those for New Jersey and Massachusetts. The commenter added that allowing emissions averaging can further reduce the costs.

Response:

See the preamble for EPA's discussion of Hg control technology, and IPM documentation (available in the docket) for EPA's assumptions regarding the capital costs of FGD and ACI.

Comment:

One commenter (OAR-2002-0056-3449) believed the current costs of ACI are reasonable. The commenter noted that DOE has a goal of reducing it to 1/4 of current costs. The commenter added that ACI also has low capital costs, which would allow for replacement if other technology is shown to have lower operational costs. In support, the commenter cited the U.S. DOE Report on Preliminary Cost Estimate of Activated Carbon Injection for Controlling Mercury Emissions from an Unscrubbed 500 MW Coal-Fired Power Plant.

Response:

See the preamble, and EPA's Office of Research and Development's white paper on Hg control technology for the Agency's position on the costs and availability on Hg control technologies.

Comment:

One commenter (OAR-2002-0056-2182) stated that some political leaders in Ohio argue that stricter environmental rules will cost jobs, but Ohio now has the dirtiest air in the nation. The commenter added that at the same time, Hg pollution has cost their fisheries millions and compromised public health. The commenter stated that the total health related and lost productivity costs have not been calculated. The commenter stated that Ohio can have both cleaner air and a strong economy - the key is to support pollution control vendors as a promising new industry.

Response:

EPA believes that the rule being finalized is the best approach to both remove Hg from the air and water and promote Hg-specific control technologies for use in the U.S. and around the world.

Comment:

One commenter (OAR-2002-0056-0916) stated that proposals make excessively costly restrictions on utilities.

Response:

EPA's chosen cap-and-trade approach to reducing Hg emissions will limit the cost impact on utilities relative to a command and control approach. The economic impacts of CAMR are discussed in Chapter 7 of the RIA. Several aspects of CAMR are designed to minimize the impact on energy production. First, EPA recommends a trading program rather than the use of command-and-control regulations. Second, compliance deadlines are set cognizant of the impact that those deadlines have on electricity production. Both of these aspects of CAMR reduce the impact of the proposal on the electricity sector.

Comment:

One commenter (OAR-2002-0056-1352) stated that the proposals will be harmful to the economy for lack of positive effect on the environment and disruption of energy supplies.

Response:

The benefits and costs of CAMR are discussed in the RIA. It should be noted that according to EO 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use,

this rule is not significant, measured incrementally to CAIR, because it does not have a greater than 1 percent impact on the cost of electricity production and it does not result in the retirement of greater than 500 MW of coal-fired generation.

Several aspects of CAMR are designed to minimize the impact on energy production. First, EPA recommends a trading program rather than the use of command-and-control regulations. Second, compliance deadlines are set cognizant of the impact that those deadlines have on electricity production. Both of these aspects of CAMR reduce the impact of the proposal on the electricity sector.

Comment:

One commenter (OAR-2002-0056-1573) stated that in setting its reductions targets and compliance deadlines, EPA should fully consider the complexities of this new regulatory program and the costs of compliance. The commenter stated that the power generation industry finds itself facing the biggest round of emission reductions in its history. The commenter pointed out that the power generation industry also faces substantial uncertainty because power plant Hg controls have yet to be commercially demonstrated. The commenter was keenly aware that some view compliance cost estimates on the part of industry as little more than "crying wolf" whenever a new regulatory requirement is imposed. However, the commenter noted their experience in implementing controls under the NO_x SIP Call. The commenter stated that EPA originally projected that two-thirds of the controls installed for NO_x SIP Call compliance would consist of Selective Non-Catalytic Reduction (SNCR) controls, with the remaining one-third mostly consisting of Selective Catalytic Reduction (SCR) controls. The commenter also stated that EPA also estimated SCR capital costs as about $60/kW. Now that companies have installed most of their NO_x controls, the commenter stated that EPA substantially underestimated compliance costs. The commenter stated that across the industry, the vast majority of the NO_x SIP Call controls have been SCR, with few installations of SNCR. The commenter opted to install nine SCRs with no SNCR at all. Contrary to EPA's estimated compliance costs of $60/kW, the commenter's actual installed SCR costs were more than double that figure. The commenter urged EPA to carefully assess the lessons learned from the regulatory initiatives of the recent past.

Response:

EPA is addressing uncertainty in the cost of Hg emissions control under CAMR by having a first phase cap that is equal to the projected co-benefit Hg reductions under CAIR in 2010, and thus does not require the installation of Hg specific control. Additionally, the second phase cap of 15 tons is also set with consideration for cost uncertainty faced by the industry. EPA believes that the use of a Hg cap-and-trade program will lead to the development of more efficient and cost effective Hg control technology options through the market incentives provided by the cap-and-trade mechanism.

Comment:

One commenter (OAR-2002-0056-2067) stated that in addition to the limitations with

existing control technology, structural barriers also exist in terms of monitoring equipment. The commenter stated that to adequately demonstrate removal of Hg, monitoring equipment, such as continuous emissions monitoring systems or sorbent trap monitoring technology, must also be installed. According to the commenter, the cost of monitoring equipment, as well as the cost of its operation and maintenance, is significant, and no monitoring technology has emerged that is both cost effective and accurate. The commenter asserted that compliance standards must recognize the limited development of such monitoring technology as well.

Response:

The final rule contains flexibility by allowing sources to account for their Hg emissions by using Hg CEMS, sorbent trap monitoring systems (or a combination thereof), and, in some cases, using low mass provisions. EPA disagrees with the commenter and believes that field tests have demonstrated Hg CEMS to be cost effective, accurate, and reliable. The Hg CEMS have performed adequately for several months and meet the Ontario-Hydro Reference Method specifications. Furthermore, several dry chemistry Hg CEMS are currently being tested at sites that represent the most challenging conditions and the Agency plans to share with industry the results of such experiences to facilitate the selection of appropriate monitoring methodology. EPA is also confident that substantial advancement of Hg CEMS will occur before the implementation of the rule and as other monitoring techniques may become available, is allowing the use of systems that can meet performance-based specifications. The performance-based approach allows for use of various suitable sampling and analytical technologies while maintaining a specified and documented level of data quality.

Comment:

Several commenters (OAR-2002-0056-1269, -2065, -2074, -2082) asked how much will plants increase rates as a result of the proposals.

Response:

The impact of CAMR on retail electricity prices relative to CAIR is projected to be less than 1 percent. This is discussed in more detail in Chapter 7 of the RIA.

Comment:

One commenter (OAR-2002-0056-2160) was concerned about the potential economic impacts of losing their bituminous coal market. The commenter asserted that to meet stringent and possibly unattainable limits, plants that burn bituminous coal mined in Illinois will switch to subbituminous coal because of the cost, less stringent limit, or unavailability of control equipment. The commenter stated that fuel switching would have a devastating economic effect on their coal industry (the Illinois coal market will fail), associated industries, and their tax base. The commenter asserted that fuel neutral rules would avoid this effect.

Response:

The reductions in emissions from the power sector under CAIR and CAMR will be met through the installation of pollution controls for Hg, SO_2, and NO_x removal. The pollution controls can achieve up to a 95 percent SO_2 removal rate, which allows industry to rely more heavily on local bituminous coal in the eastern and central parts of the country that has a higher sulfur content and is less expensive to transport than western subbituminous coal.

Comment:

One commenter (OAR-2002-0056-2160) stated that there is an increased risk on capital investment because of the uncertainty in the availability of control technology. The commenter stated that obtaining financial backing for purchasing equipment will require larger outlays from power companies (lending institutions avoid risk). The commenter believed these increased costs will be passed on to consumers, thus harming the State's ability to provide inexpensive electric power-an economic asset. The commenter stated that the proposed rules should be reviewed to determine the availability of technologies which have minimal risk in attaining the necessary emissions performance.

Response:

EPA's Office of Research and Development has produced a white paper (available in the docket) that assess the current state of Hg emissions control technology. EPA has set the first phase cap at a level that represents projected co-benefit Hg emission reductions that will occur under CAIR as of 2010, and the 15 ton cap in 2018 allows sources adequate time for the installation of the necessary pollution controls.

Several aspects of CAMR are designed to minimize the impact on energy production. First, EPA recommends a trading program rather than the use of command-and-control regulations. Second, compliance deadlines are set cognizant of the impact that those deadlines have on electricity production. Both of these aspects of CAMR reduce the impact of the proposal on the electricity sector.

Comment:

One commenter (OAR-2002-0056-1969) stated that monitoring costs for small units will be disproportionate to the costs of compliance with the MACT emissions limit. The commenter supported lower frequencies and lower cost monitoring requirements for those units that emit under 25 pounds per year.

Response:

The Agency has decided to use a cap-and-trade program to control Hg emissions. Complete and accurate accounting of Hg emissions is required for a credible cap and trade program. Therefore, Hg CEMS or sorbent traps are required in the final rule. However, qualifying, low emitting sources may comply with today's monitoring requirements by using conservative default Hg emission factors and annual or semi-annual stack testing.

Comment:

One commenter (OAR-2002-0056-2075) stated that if the proposed regulations result in the closure of coal-fired generation plants, there would be significant fallout for the state, regional, and local economies. The commenter stated that excessive regulation decreases the capacity of U.S. companies to compete in global markets. The commenter also stated that when the costs of compliance with environmental regulations rise, U.S. firms are less able to perform optimally. The commenter further stated that the entire economy suffers. The commenter stated that for Texas, coal mining results in an addition to business activity of:

$2.438 billion in annual Total Expenditures;
$0.957 billion in annual Gross Product;
$0.713 billion in annual Personal Income;
$0.258 billion in annual Retail Sales; and
12,684 Permanent Jobs.

The commenter stated that East Texas is where the majority of Texas' coal mines are concentrated. The commenter further stated that the economic impact of coal mining on the regional economy is:

$1.356 billion in annual Total Expenditures;
$0.526 billion in annual Gross Product;
$0.405 billion in annual Personal Income;
$0.154 billion in annual Retail Sales; and
7,210 Permanent Jobs.

The commenter stated that the total economic impact of coal mining and coal-fired electric generating plants is estimated to be:

$10.498 billion in annual Total Expenditures;
$3.516 billion in annual Gross Product;
$2.081 billion in annual Personal Income;
$0.584 billion in annual Retail Sales; and
33,197 Permanent Jobs.

Response:

The economic impact of CAMR is discussed in Chapter 7 of the RIA. It should be noted that according to EO 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use, this rule is not significant, measured incrementally to CAIR, because it does not have a greater than a 1 percent impact on the cost of electricity production and it does not result in the retirement of greater than 500 MW of coal-fired generation.

Several aspects of CAMR are designed to minimize the impact on energy production. First, EPA recommends a trading program rather than the use of command-and-control

regulations. Second, compliance deadlines are set cognizant of the impact that those deadlines have on electricity production. Both of these aspects of CAMR reduce the impact of the proposal on the electricity sector.

Comment:

One commenter (OAR-2002-0056-2578) performed an analysis that compared the Hg cap-and-trade provisions of the Clear Skies Act (CSA) of 2003 to a generic MACT standard of 2.2 lb/trillion Btu for all generating units. The commenter stated that these two policies are reasonably similar to the two alternative Hg rules proposed by EPA. The commenter's cost-effectiveness analysis found that the CSA cap and trade alternative would cost less than an illustrative MACT rule on a present-value basis by about a factor of 3, yet it would produce slightly larger deposition changes and MeHg exposure reductions by 2020. The commenter pointed out that in either case, however, the effectiveness of the policies in reducing deposition of Hg in the U.S. appeared small. The commenter analyzed EPA's December 2003 rule proposals using the same analysis framework as before (but with greater detail and updated modeling assumptions) and found a similar comparison. According to the commenter, the relative cost-effectiveness of the proposed cap and trade rule compared to the proposed MACT rule appears to be even greater than was estimated for the two alternatives studied in the earlier analysis. The commenter stated that the primary apparent difference between the proposed MACT rule and the cap and trade rule is that MACT provides earlier reductions than the proposed cap and trade policy. However, this earlier implementation, according to the commenter, leads to a small percentage change in deposition (and hence in exposure) but at an additional $8 billion (present value) in costs.

Response:

EPA is finalizing a cap-and-trade program for Hg under section 111 of the CAA. EPA believes there are a number of advantages to this approach relative to a MACT approach. First, the cap-and-trade program will set a fixed limit on the total number of allowable Hg emissions, which cannot be exceeded even when existing plants are expanded and new plants are constructed. Second, a trading program provides a market incentive for sources to reduce emissions beyond the required level, because of the ability to bank allowances, or sell allowances on the market. This incentive acts to stimulate innovations in control technology that might not occur under a command and control approach such as MACT, and will also lead to cheaper emissions reductions overall.

Comment:

One commenter (OAR-2002-0056-2634) stated that the cost of compliance should be proportionate to the intended environmental benefit. The commenter noted that the purpose of controlling Hg emissions from power plants is to address potential adverse impacts that exposure to Hg can have on human health and the environment. The commenter pointed out that, more specifically, EPA states in the preamble to the notice of proposed rulemaking (NPR) that the focus of this rulemaking relates to "oral exposure of MeHg as it is the route of primary interest

for human exposures" [69 FR 4658]. The commenter pointed out that EPA further states that MeHg "is typically formed by biological processes after mercury has precipitated from the air and deposited into water bodies" [69 FR 4657]. The commenter stated that, therefore, when weighing the cost of compliance against the environmental benefit, it is imperative that EPA consider the impact of the proposal in terms of reductions in Hg deposition (and ultimate human exposure) versus reductions in emissions. The commenter pointed out that over 70 percent of Hg deposition in the U.S. comes from sources outside of the U.S., and in much of the western U.S., between 80 percent and 100 percent of the deposition originates outside of the U.S. ["New Findings on Mercury Dynamics," EPRI et al., presented at the 7th Electric Utilities Environmental Conference, Tucson, AZ, January 21, 2004]. The commenter stated that modeling performed by EPRI indicates that a reduction of Hg emissions from coal-fired power plants to 15 tpy (an approximate 70 percent reduction from 1999 levels) would result in only a 6.9 percent reduction in deposition. The commenter stated that it has not been determined whether this level of reduction in deposition will effectively reduce the levels of MeHg in the environment, which is the stated focus of the proposed rule. The commenter stated that the level of Hg reductions and the means to achieve those reductions must be "cost effective" in terms of the ultimate reduction in exposure to MeHg.

Response:

Executive Order 12866 requires EPA to estimate and compare the costs and benefits for major regulatory actions. It does not require that the monetizable benefits exceed the monetizable costs. However, in the design of this rulemaking, EPA has carefully weighed the costs of controlling Hg from utilities, the benefits resulting from these reductions and other factors (e.g. the desire to provide global leadership in reducing Hg emissions). As detailed in the preamble to this rulemaking and the regulatory support documents, EPA has selected a regulatory approach which balances all these factors.

Comment:

One commenter (OAR-2002-0056-2721) strongly disagreed with EPA's estimated annual monitoring, reporting and recordkeeping costs for compliance with this regulation. The commenter stated that EPA estimated the annual reporting costs to be $48.4 million, which equates to approximately $85,000 per unit. The commenter claimed this number is extremely low when taking into account the annual Hg compliance audit, which is budgeted over $30,000 for a single annual audit alone. The commenter pointed out that the number of audits can be increased to semi-annual or more frequent based on the actual monitor's performance. The commenter stated that the capital expense that EPA reported was approximately $117,000 per unit. The commenter submitted that this value is also extremely understated. According to the commenter there are presently no long-term Hg monitoring systems in-place at a coal-fired facility. The commenter pointed out that the current state of monitoring is very labor intensive and involves an extremely highly trained workforce. The commenter stated that the current monitor itself is over $100,000 alone. The commenter further stated that this does not account for secondary systems required to support this equipment, e.g., monitor cabinets, air supplies, electrical power supply, electronic communication networks, data storage devices, software

enhancements, etc.

Response:

The cost information is largely based on documents generated for the Clean Air Markets Division, specifically the Cost Analysis of Mercury Monitoring Techniques done by Arcadis , on November 2003, that is part of the docket. This analysis provides an overview of the cost information gathered and analyzed to date, focusing on sources such as utility boilers that are required to monitor Hg emissions under the proposed rule. EPA believes that sources will probably operate the systems taking advantage of installations currently in use under other Clean Air Act programs, such as CEMS shelters, platforms, etc and will not be the focus of further analysis. In addition, it is estimated that no major structural modifications are needed for access or support equipment, and that power is available in the area. Based on the information provided by the Arcadis report, EPA estimates that the average CEMS cost will be $80,000 and that the annual operating cost, with one RATA test done based on the Ontario Hydro method will be also about $80,000.

EPA believes that field tests have demonstrated Hg CEMS to be accurate and reliable. The Hg CEMS have performed adequately for several months and meet the Ontario-Hydro Reference Method specifications. EPA is also confident that substantial advancement of Hg CEMS will occur before the implementation of the rule and as other monitoring techniques may become available, is allowing the use of systems that can meet performance-based specifications. In addition, the final rule contains flexibility by allowing sources to account for their Hg emissions by using Hg CEMS, sorbent trap monitoring systems (or a combination thereof), and, in some cases, using low mass provisions.

Comment:

One commenter (OAR-2002-0056-2843) expressed concern that the Hg reduction requirements proposed by the EPA for new plants fueled with Powder River Basin (PRB) coals will be so restrictive that they will limit the fuels that can be burned in new facilities. The commenter's analysis followed the forecast of available PRB fuels performed by the National Mining Association (NMA), the Subbituminous Energy Coalition (SEC), and the Center for Energy and Economic Development CEED); such forecasts generally suggest that the available fuels will be less than 10 percent of the 360 million tons of coal mined annually in the PRB. The commenter stated that if this forecast is correct, the cost of these fuels will likely be impacted so substantially that the development of new generating resources using PRB coals might be expected to be diminished substantially.

Response:

The impacts of CAMR on coal production and coal costs are discussed in Chapter 7 of the RIA.

Comment:

One commenter (OAR-2002-0056-2843) believed that new coal-fired generating plants are vital if affordable electric energy prices are to be ensured in the future. The commenter agreed with the DOE, Energy Information Administration, (DOE/EIA) Annual Energy Outlook 2004 forecast that projects a need for an additional 112 Gigawatts of new coal generating capacity by 2025. The commenter believed that any new Hg emissions standard that would make such new coal-fired generation either technically or economically infeasible will compel the U.S. power generation industry to rely upon other fuel sources, including importation of "compliance coal" or reversion to natural gas-fired combustion turbines as the only near- to mid-term alternatives to provide large blocks of new electric generation capacity. The commenter stated that consequently, imposition of such a standard would stimulate additional, significant increases in the price of compliance coals and natural gas as well as a surge in imports associated with increased demand for LNG. The commenter contended that such an increase in imports would further exacerbate U.S. dependence upon off-shore energy supplies. The commenter did not believe that this outcome has been considered in the policy debate about stringency of Hg emissions control on U.S. coal-fired power plants. The commenter felt that such an outcome should be unacceptable given the adverse consequences of energy inflation and further reliance upon imported energy.

Response:

The projected economic and energy impacts of CAMR are discussed in Chapter 7 of the RIA. It should be noted that, according to EO 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use, this rule is not significant, measured incrementally to CAIR, because it does not have a greater than a 1 percent impact on the cost of electricity production and it does not result in the retirement of greater than 500 MW of coal-fired generation. In fact, CAMR is not projected to result in any additional coal retirement relative to CAIR.

Several aspects of CAMR are designed to minimize the impact on energy production. First, EPA recommends a trading program rather than the use of command-and-control regulations. Second, compliance deadlines are set cognizant of the impact that those deadlines have on electricity production. Both of these aspects of CAMR reduce the impact of the proposal on the electricity sector.

Comment:

One commenter (OAR-2002-0056-2843) asserted that the adverse impact of the proposed rulemaking upon development of new coal-fired electric generation will have a direct bearing on the financial condition of, and prospects for electric utilities and independent power producers (IPP) alike. Specifically, the commenter stated that as a consequence of the collapse of wholesale power markets and the malaise gripping the IPP sector for the past two years, investors and lenders require assurance that new plants meet rigorous requirements of financial performance on a long-term basis. The commenter pointed out that such requirements include the need to incorporate fixed price, turnkey construction with strong technology performance guarantees, long-term fuel contracts, long-term off-take agreements with credit-worthy entities, and the ability to achieve compliance with current (as well as contemplated) environmental

requirements.

Response:

The projected economic and energy impacts of CAMR are discussed in Chapter 7 of the RIA. It should be noted that, according to EO 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use, this rule is not significant, measured incrementally to CAIR, because it does not have a greater than a 1 percent impact on the cost of electricity production and it does not result in the retirement of greater than 500 MW of coal-fired generation. In fact, CAMR is not projected to result in any additional coal retirement relative to CAIR.

Several aspects of CAMR are designed to minimize the impact on energy production. First, EPA recommends a trading program rather than the use of command-and-control regulations. Second, compliance deadlines are set cognizant of the impact that those deadlines have on electricity production. Both of these aspects of CAMR reduce the impact of the proposal on the electricity sector.

35 Comment:

One commenter (OAR-2002-0056-3327) claimed that without changes requested by the commenter, the utility Hg reductions rule (UMRR) will eliminate Gulf Coast Lignite from the marketplace. The commenter submitted that if Texas loses Gulf Coast Lignite, it will lose more than $17 billion annually in direct and indirect benefits, including 8,000 direct jobs and more than 100,000 indirect jobs. The commenter added that some rural communities will lose more than 50 percent of their tax revenues. The commenter also stated that without Gulf Coast Lignite, it will become nearly impossible to develop a balanced energy policy or ensure the reliability and affordability of electric power in Texas.

Response:

The impacts of CAMR on coal production are discussed in Chapter 7 of the CAMR RIA. EPA is not projecting the shutdown of any coal capacity relative to CAIR.

Comment:

One commenter (OAR-2002-0056-3403) requested that the EPA ensure that any future Hg reductions requirements be achieved in an efficient and cost effective manner. The commenter stated that as a not-for-profit, they will be forced to pass along the costs of meeting new Hg emissions reduction requirements to their consumer-owners.

Response:

EPA is finalizing a cap-and-trade program for Hg under section 111 of the CAA, which will provide for efficient and cost-effective Hg emissions reductions relative to a command and control approach.

RESPONSE TO SIGNIFICANT PUBLIC COMMENTS ON THE PROPOSED CLEAN AIR MERCURY RULE

Received in response to:

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 4652; January 30, 2004)

Supplemental Notice for the Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 12398; March 16, 2004)

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources, Electric Utility Steam Generating Units: Notice of Data Availability
(69 FR 69864; December 1, 2004)

Docket Number OAR-2002-0056

8.0 COMPLIANCE WITH EXECUTIVE ORDERS AND STATUTES

US Environmental Protection Agency
Emissions Standards Division
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

15 March 2005

General Outline

8.0 COMPLIANCE WITH EXECUTIVE ORDERS AND STATUTES

8.1 REGULATORY IMPACT ANALYSIS (EO 12866, ANALYSIS OF ALTERNATIVES, BENEFITS, HEALTH COSTS)

Comment:

One commenter (OAR-2002-0056-4910) stated that EPA failed to meet the requirements of several executive orders. Specifically the commenters stated that EPA failed to perform a rigorous economic analysis of the alternative regulatory options pursuant to EO 12866, which would demonstrate that more stringent MACT standards were achievable. The commenters claimed that tighter limits would result in insignificant increased cost compared to the proposal while providing benefits (preventing thousands of premature deaths). Commenter OAR-2002-0056-2836 stated that U.S. Senators and Congressmen contended EPA did not comply with EO 12866 to fully analyze the impacts of its proposal using the best scientific information available. The commenter stated that EPA's first option would have been to abandon the regulatory determination the listing decision and the settlement agreement, thus the proposal should have contained a much more comprehensive discussion of the environmental, energy, economic, and public health impacts of the proposed action.

Six commenters (OAR-2002-0056-1471, -1606, -1755, -1817, -1823, -2127) stated that EPA did not fulfilled its obligations under EO 12866 because it did not assess the costs and benefits of available regulatory alternatives. The commenters stated that a full cost-benefit analysis was required for all available technologies, and that EPA also must analyze the benefits of Hg emission control reductions considering such factors as premature deaths, emergency room admissions, and asthma. The commenter stated that these analyses have been published by the Mt. Sinai School of Medicine's Center for Children's Health and the Environment as well as by the Harvard School of Public Health.

Response:

EPA has developed a more complete assessment of its regulatory approach as part of this final rulemaking action. The Regulatory Impacts Assessment (RIA) which accompanies this rulemaking contains an assessment of the costs and benefits of the selected approach as well as regulatory alternatives.

Comment:

Several commenters (OAR-2002-0056 -2152, -2235, -2286, -3514, -3560) questioned whether the benefits of the proposed regulations justify the costs. One commenter (OAR-2002-0056-3514) supported protecting public health and was prepared to make reasonable additional reductions in power plant Hg emissions. In fact, the commenter was actively funding and participating in research into finding technologies that would control Hg emissions from lignite coal, as none are currently available. The commenter also felt it was important for any costly environmental regulations deliver identifiable health and environmental benefits. The

commenter did not believe that EPA demonstrated that reductions of Hg emissions from U.S. power plants would deliver the expected health benefits. The commenter noted that recent studies showed that even very significant reductions in power plant emissions would have very little impact in local or nationwide deposition. The commenter pointed out that in the January 30 proposed rule, EPA stated that they "cannot currently quantify whether, and the extent to which, the adverse health effects occur in the populations surrounding these facilities, and the contribution, if any, of the facilities to those problems" and "the relationship between Hg emission reductions from Utility Units and methylmercury (MeHg) concentrations in fish cannot be calculated in a quantitative manner with confidence."

The second commenter (OAR-2002-0056-3560) pointed out that the current proposed Hg rules failed to adequately consider the cost and benefits associated with the MACT or cap and trade approach to Hg emissions. The commenter noted that EPA cites its own study that apparently "supports a plausible link between anthropogenic releases of mercury from industrial and combustion sources in the U.S. and methylmercury in fish" [69 Fed. Reg. 4652, 4658 (proposed January 30, 2004)]. The commenter further noted that EPA admitted as follows that such a purported link is untenable: "Given the current scientific understanding of the environmental fate and transport of [methylmercury], it is not possible to quantify how much of the MeHg in fish consumed by the U.S. population is contributed by U.S. emissions relative to other sources of Hg (such as natural sources and re-emissions from the global pool). As a result, the relationship between Hg emission reductions from Utility Units and MeHg concentrations in fish cannot be calculated in a quantitative manner with confidence. In addition, there is uncertainty regarding over what time period these changes would occur."

The commenter added that EPA found that nine of the top ten fish/shellfish consumed by U.S. residents came from saltwater. [See Jon M. Heuss, An Examination of the Claims that Utility Mercury Emissions are Poisoning US. Children and Creating Toxic Hot Spots, The Annapolis Center for Science-Based Public Policy, at 5.] The commenter submitted thus, reducing power plant Hg emissions may not have any significant impact on the primary exposure route, which is human consumption of ocean fish. The commenter added that, in fact, EPA has readily acknowledged that U.S. utilities are estimated to account only for roughly 1 percent of the total global emissions of Hg. [See id., at 3.] The commenter, therefore, believed that the exact extent and nature of the health benefits to be derived from reducing Hg emissions at power plants was, at best, unclear. In all probability, the reduction of Hg emissions obtained by these regulations (even eliminating all power plant emissions) would be unlikely to yield a measurable reduction in Hg levels in the primary exposure pathway. The commenter concluded that in light of the uncertain health benefits to be gained from reduction of Hg from power plants, it appeared that the proposed Hg regulations should focus more carefully on the costs and benefits of reducing Hg emissions.

Three commenters (OAR-2002-0056-2152, -2235, -2286) noted that EPA did not develop a cost-benefit analysis and recommended that EPA delay the rules until there is proven technology. Two commenters (OAR-2002-0056-0699, -4328) urged EPA to find a compromise between the environment and economics and to temper the cost of the rule according to the costs to industry (employers) and to consumers.

Response:

EPA has developed a more complete assessment of its regulatory approach as part of this final rulemaking action. The RIA which accompanies this rulemaking contains an assessment of the costs and benefits of the selected approach as well as regulatory alternatives.

As part of its analysis of the final rule, EPA has estimated that some of the health benefits of reducing Hg from utilities. At this time EPA is only able to provide quantitative estimates of the benefits of reducing IQ decrements associated with exposure to MeHg for a portion of the U.S. population, women of child-bearing age. The RIA for this rule contains this analysis in Chapters 10 and 11 .

Comment:

One commenter (OAR-2002-0056-2578) provided results of an analysis concluding that the Hg emissions reduction proposed by EPA would result in slightly lower exposure to Hg by U.S. women of childbearing age and that the improvements to public health would vary by location across the U.S. According to the commenter, the analysis indicated, that in comparison to 1999 levels, the average exposure would decrease by about 1.46 percent across the U.S. under the Cap & Trade scenario while under the MACT or CAIR scenarios, the average exposure would be reduced by about 0.9 percent. The commenter's comparison of relative changes in exposure under the two 2020 scenarios, relative to 1999, concluded that, with respect to the deposition case under CAIR, Cap & Trade was, in every case, more protective than MACT (that is, for every state for which data are available, there is a greater decrease in exposure under C&T than under MACT).

Response:

Through this rulemaking and the separate CAIR rule, EPA is limiting Hg emissions from utilities. As explained in the preamble to the final rule, EPA believes that these rules will provide a substantial positive step in reducing the health effects which may result from the release of Hg from these utilities.

EPA has developed a more complete assessment of its regulatory approach as part of this final rulemaking action. The RIA which accompanies this rulemaking contains an assessment of the costs and benefits of the selected approach as well as regulatory alternatives.

Comment:

One commenter (OAR-2002-0056-3538) disputed EPA's co-benefits analysis, stating that, based on IAQR and Clear Skies, the analysis did not properly account for Hg. The commenter stated that the costs and benefits of IAQR and Clear Skies, which would reduce Hg as a co-benefit, do not include any monetized or quantified health and environmental benefits for Hg reduction. The commenter believed that if the SO_2 and NO_x limits in the IAQR represent EPA's approach for Hg reduction, then the maximum achievable control technology for Hg must be at least equivalent to the "diminishing returns (knee of the cost curve)", and likely beyond

that, to account for additional Hg benefits. The commenter stated that if the SO_2 and $_{NOx}$ removal technologies do represent MACT, EPA must then require the used of scrubbers to the extent they are cost- effective for Hg and require SCR for $_{NOx}$ control year round.

Response:

EPA set the first phase cap of CAMR at a level that represents the co-benefit Hg reductions that will occur as a result of installation of NO_x and SO_2 control technologies under CAIR. EPA assessed the monetary benefits of Hg reductions in the first phase of the program in the RIA. EPA has not asserted that NO_x and SO_2 removal technologies represent MACT. EPA's second phase cap of 15 tons will require the installation of Hg-specific control technology at many sources, and will provide a continuous incentive for the development of increasingly efficient and cost-effective control technologies for Hg.

Comment:

Several commenters (OAR-2002-0056-2380, -3353, -3413, 4139) questioned the adequacy of EPA's benefits estimate. Commenter OAR-2002-0056-4139 requested that EPA provide estimates of the potential environmental benefits (i.e., reduction in fish Hg levels) and time lines under the proposed approaches developed with EPA's own recommended approach (used in TMDL development) for relating the reductions in Hg deposition to associated reductions in fish Hg levels ("A Qualitative Spatial Link Between Air Deposition and Fish Tissue, Cocca, 2001). If it is not feasible to provide this, the commenter requested that EPA provide a more thorough description of the limitations of the methodology and remaining data gaps which need to be addressed. The commenter claimed that EPA's position is that health benefits cannot be assumed or estimated quantitatively and that a specific change in total Hg emissions cannot be related to any specific change in MeHg concentration in fish or health improvements. The commenter asserted that EPA used this position as the justification for not performing a quantitative cost benefit analysis.

Two commenters (OAR-2002-0056-2380, -3413) stated that EPA had not accounted for the health costs of the proposed rule. The commenters stated that the $15 billion benefit cited by EPA was basically a savings to industry and requested that EPA perform a health impact analysis for the medical costs and illness/deaths of the proposed alternatives.

Commenter OAR-2002-0056-3353 requested that EPA provide its best estimate of the reduction in the Hg levels in the seafood consumed in the U.S. compared to complete elimination of Hg, and requested a more explicit analysis of the extent of harm resulting from Hg exposures. The commenter felt that States should consider the total benefits of Hg control. The commenter further stated that if elimination of Hg would not result in a significant reductions in fish advisories, this should be acknowledged by EPA.

Response:

EPA has developed a more complete assessment of its regulatory approach as part of this

final rulemaking action. The RIA which accompanies this rulemaking contains an assessment of the costs and benefits of the selected approach as well as regulatory alternatives.

As part of its analysis of the final rule, EPA has estimated that some of the health benefits of reducing Hg from utilities. freshwater fish. At this time, EPA is only able to provide quantitative estimates of the benefits of reducing IQ decrements associated with exposure to MeHg for a portion of the U.S. population, women of child-bearing age. The RIA for this rule contains this analysis in Chapters 10 and 11.

Comment:

Commenter OAR-2002-0056-3459 contended that EPA failed to meet the requirements of EO 12866 (Regulatory Planning and Review) because it did not undertake a rigorous economic analysis of alternative MACT regulatory options. In choosing among alternative approaches, the commenter believed that EPA should select the approaches that maximize net benefits. The costs and benefits include both quantitative measures (to the fullest extent they can be usefully estimated) and qualitative measures of costs and benefits that are difficult to quantify but essential to consider. The commenter stated that EPA published guidance in 1996 for preparing these analyses, and failed to follow either the guidance or the EO requirements. The commenter claimed that EPA did not seriously evaluate alternatives to the MACT floor (e.g., floor based on no subcategorization or other subcategorization criteria) and did no assessment of alternative beyond-the-floor options (except for providing excuses why the standards ignore available techniques). The commenter asserted that EPA then did a superficial cost and benefit assessment of the MACT standard against a section 111 cap and trade alternative. The commenter stated that a rigorous economic analysis demonstrated that more stringent MACT standards are achievable, feasible, highly cost- effective, and would provide substantial additional human health benefits (the incremental benefits would be well in excess of incremental costs). The analysis used EPA's emission rates (minus what the commenter deemed unjustifiable statistical adjustments), subcategorization by fuel rank (bituminous, subbituminous, lignite), and other EPA methods and procedures. The results of the commenter's analysis showed that EPA's less stringent proposal was arbitrary and capricious. The commenter's alternative was said to reduce Hg far more, and more rapidly, and reduce particulate-related deaths far more at costs very close to those for EPA's less stringent proposals (about $5 billion more) and the commenter asserted that these costs were conservatively (high) estimates. The commenter's alternative scenario resulted in slight shifts towards more bituminous coal and moderate declines in subbituminous and lignite use. A similar shift was observed with EPA's proposal (or any regulatory approach), but the commenter stated that the public health and environmental benefits far outweigh the impacts of coal market shifts. The commenter's alternative shifted coal production from Appalachia and the West to the Interior region, and would reduce coal use by less than 1 percent. The commenter stated that EPA's proposal had the same shift but increased coal use by about 6 percent. The alternative resulted in an increase in electricity prices of about one-half cent per kilowatt hour (or 7 percent) for all power regions relative to EPA's proposal. Coal prices under the alternative were essentially unchanged, compared to EPA's proposal and the price of natural gas was essentially unaffected. The commenter asserted that the costs of the alternative were more than offset by the total estimated

benefits of $28 billion in 2010 and $6.9 billion in 2020. Additional benefits would be even higher if the 11 health and welfare benefits EPA identified but did not assess were included. The commenter estimated that in 2010, the benefits of the alternative would exceed costs by almost 6 to 1. The commenter stated that even more stringent limits are cost effective and that EPA must consider and analyze them to fulfill EO 12866 requirements.

Response:

EPA has conducted the analyses required by EO 12866 and the results are provided in the preamble of the final rule.

Comment:

One commenter (OAR-2002-0056-2251) stated that, based on the preamble, "... the relationship between Hg emission reductions from Utility Units and MeHg concentrations cannot be calculated with confidence," and asserted that EPA should re-examine the risk to the American people caused by coal-based utility Hg emissions and consider the health implications of Hg regulation in a more holistic fashion, so that rules designed to reduce Hg in fish actually reflect and address the likelihood of health benefits and the expected timing of such benefits and do not result in arbitrary administrative actions or unintended, negative health consequences for the public at large. The commenter stated that EPA had a dual responsibility in regard to public health and emissions from power plants. First, the Agency must protect the public from exposure to criteria air pollutants and HAP, as defined by the CAA. Second, EPA must assess the impact of its regulations in a broader perspective."

Response:

EPA has analyzed the economic and benefits impacts of the final rule and provided a discussion of the results in the preamble to the final rule and in the RIA.

8 Comment:

One commenter (OAR-2002-0056-1842) questioned EPA's analysis stating that only a few air toxics accounted for most of the weight of toxics emitted. The commenter noted, however, that there is a huge difference in toxicity equivalency quotient (TEQ) between HAP. The commenter stated that the average plant has a TEQ of 242,000, and that this quotient already reflected 90 percent removal of the metals other than Hg. The commenter concluded that the quotient with no air pollution control equipment could easily be 800,000, and if one were to require 90 percent reduction from this uncontrolled level then the TEQ or toxic equivalent would be 80,000. The commenter stated that if Hg were treated separately, the raw quotient would be 700,000, and that meeting a 70,000 quotient limit could easily be accomplished with the normal particulate equipment and SO_2 scrubber.

The commenter stated that the original EPA draft listed Hg with a lesser quantity emission rate (LQER) of 0.1. The commenter compared the Hg impact with the LQER both at

the 0.001 level and at 0.01 (the toxicity for lead and chromium). The commenter stated that these comparisons should give legislators pause before requiring a 90 percent Hg reduction. Reducing Hg the extra 10 percent could add as much as 10 mils/kWh to electricity cost. The commenter concluded that for the base case, an extra 10 percent reduction of HCl, chromium, and lead would accomplish the same toxicity reduction but at a far lower cost (less than 0.5 mil/kWh). The commenter stated that in the case where Hg was assigned a lower toxicity, the extra 10 percent Hg reduction only reduced total toxicity by 0.5 percent. The calculations were based on nationwide annual emissions as reported in the TRI inventory.

Response:

As discussed in the preamble to the final rule, EPA believes that Hg is the pollutant of concern from coal-fired Utility Units. However, together the multipollutant benefits of CAIR and CAMR will also lead to reductions of the pollutants the commenter notes.

Comment:

One commenter (OAR-2002-0056-2899) questioned EPA's analysis stating that reducing Hg emissions from coal-fired power plants appeared to do little to reduce the public health risk from Hg exposure. The commenter noted that EPA has repeatedly said that it cannot quantify the linkage between Hg emissions from coal-fired power plants and Hg levels in fish and observed that in the preamble to the proposed rule, EPA presented an assessment of the benefits that it predicted would result from its proposed Hg limits. The commenter noted that with regard to Hg, EPA stated: "the Agency believes that the key rationale for controlling Hg is to reduce public and environmental exposure to Hg, thereby reducing risk to public health and wildlife. Although the available science does not support quantification of these benefits at this time, the Agency believes the qualitative benefits are large enough to justify substantial investment in Hg emission reductions." The commenter stated that EPA's speculation about the possible benefits from the control of Hg emissions from coal-fired power plants is not borne out by detailed analyses performed by EPRI.

The commenter stated that in May 2003, EPRI released a technical report analyzing the cost effectiveness of the proposed Clear Skies legislation and a hypothetical MACT standard. According to the commenter, the analysis first used an econometric model to predict how utilities would act to comply with the two regulatory structures, then used an atmospheric fate and transport model to predict how the resulting changes in Hg emissions would affect a number of receptors in specific source regions. The deposition information was then used to estimate the change in MeHg exposure to women of childbearing age. These changes in MeHg exposure were then compared to the estimated costs of each regulatory scheme.

According to the commenter, EPRI's analyses found that Hg emissions from coal-fired power plants contributed less than 8 percent of the Hg deposited in the U.S., and that a 10 percent reduction in national ionic Hg emissions from coal-fired power plants would result in a 0.75 percent reduction in U.S. Hg deposition while a 10 percent reduction in national elemental Hg emissions would lower U.S. Hg deposition by 0.03 percent. According to the commenter,

even if Hg emissions from coal-fired power plants were reduced to 15 tons per year, the Hg deposition in the U.S. would only be reduced by approximately 5 percent assuming the reductions were linearly related.

Response:

EPA has developed a more complete assessment of its regulatory approach as part of this final rulemaking action. The RIA which accompanies this rulemaking contains an assessment of the costs and benefits of the selected approach as well as regulatory alternatives.

As part of its analysis of the final rule, EPA has estimated that some of the health benefits of reducing Hg from utilities. At this time EPA is only able to provide quantitative estimates of the benefits of reducing IQ decrements associated with exposure to MeHg for a portion of the U.S. population, women of child-bearing age. The RIA for this rule contains this analysis in Chapters 10 and 11.

Comment:

Commenter (OAR-2002-0056-1842) stated that utilities attempting Hg reduction were faced with a decision as to whether to install a new baghouse, with substantial capital cost, or to inject five times more carbon to an existing precipitator. The commenter stated that if a few years later the utility were told it must greatly reduce fine particulate, it might well regret its Hg removal choice. The commenter stated that toxic metal releases (lead, chromium, cadmium, etc.) were typically proportionate to the fine particulate emissions, and that an old plant which was permitted at 0.2 lbs of discrete particulate/MMBtu emitted more than ten times as much metal toxics as a newly permitted coal plant with a limit of 0.018 lbs/MMBtu. The commenter stated that fine particulate is increasingly targeted as an important health hazard, and that condensible particulate is below 2.5 microns in diameter and includes acid mist and some organics.

The commenter claimed that the installation of scrubbers due to CAIR would substantially reduce fine particulate, and that several scrubber systems installed in the early 1990s guaranteed discrete particulate reductions from 0.015 lbs/MMBtu to 0.05 lbs/MMBtu. The commenter stated that fine particles would not be captured by these systems and that most of the acid mist (condensibles) would pass through. The commenter concluded that it is necessary to address fine particulate (including metal toxics) along with Hg, which would be desirable not only because of the health benefits but because focusing on one pollutant at a time was not cost effective. The commenter cited evidence that the EPA estimates of particulate and fine particulate were much lower than the actual quantities (March 1994 and August 1994, Vol. 44 Journal of the Air and Waste Management Association.) One article from the Institute of Clean Air Companies was quoted, “Rather, the issue for ICAC is whether government regulators should give utilities the option–the voluntary choice–of responding to a possible stream of regulatory actions in an integrated cost-effective way, thus avoiding the traditional and often unsatisfactory choice of having to add successive “boxes” as regulatory requirements emerge piecemeal, one after the other.”

Comment:

One commenter (OAR-2002-0056-1842) stated that flexible incentives could dramatically lower a utility's (and its rate payers') cost of compliance with the regulatory stream, provide certainty, and elicit public praise. The commenter further suggested that incentives for non-mandated particulate and air toxics reductions would also fit nicely with ongoing efforts (e.g., the U.S. EPA's 33/50 and "cleaner/cheaper" projects, and the U.S. Department of Energy's voluntary utility greenhouse gas reduction projects) to use market and regulatory incentives to reduce dangerous emissions more quickly and cost-effectively.

The commenter stated that total U.S. utility particulate (fly ash and other discrete particles) emissions were between 437,000 tons per year (tpy) and 1.9 million tpy, compared to an EPA estimate of 700,000 tpy, and that fine particulate emissions (fly ash PM 2.5) were between 305,000 tpy and 1.7 million tpy (compared to an EPA estimate of 99,000 tpy). The commenter stated that these differences could be important in the setting of priorities and that EPA had estimated that utilities emit 1.5 million tpy of sulfate aerosols, 334,000 tpy of nitrate aerosols and 27,000 tpy of organic aerosols. The commenter recommended that the economics should be reviewed because fly ash PM2.5 emissions were 3 to 17 times greater than estimated. The commenter stated that accurate determination of PM2.5 is critical to the program to limit arsenic, beryllium, cadmium, chromium, lead, nickel, and other heavy metals.

Response:

The EPA believes that a carefully designed multipollutant approach – a program designed to regulate NOx, SO_2, and Hg at the same time – is the most effective way to reduce emissions from the power sector. EPA has just finalized the CAIR rule. EPA's modeling shows that CAIR will significantly reduce the majority of the coal-fired power plant mercury emissions that deposit in the U.S., and those reductions will occur in areas where mercury deposition is currently the highest. The Clean Air Mercury Rule is expected to make additional reductions in emissions that are transported regionally and deposited domestically, and it will reduce emissions that contribute to atmospheric mercury worldwide.

Comment:

One commenter (OAR-2002-0056-3543) stated that a thorough technical analysis of the programs established by the proposal was not possible without additional information from EPA.

Response:

EPA has conducted additional analyses as described in the promulgation preamble and provided in the docket.

Comment:

Two commenters (OAR-2002-0056-2334, -2915) were concerned about possible

restriction of energy sources. Commenter OAR-2002-0056-2334 stated that the rule would dictate air quality, energy, economic, national security and industrial competitiveness policy for the entire U.S. The commenter stated that all of these policies would be driven by whether the Rule will allow coal to be used for power generation in a cost competitive manner. The Rule would determine whether coal or natural gas will be used to meet expanding electricity demand and as a result, the price and availability of natural gas to private sector, non-utility consumers including manufacturers, homeowners and farmers. Commenter OAR-2002-0056-2915 expressed concern that reductions in Hg emissions that may be required by the final Hg rule not negatively impact the diversity of fuels that are used for electricity generation in Texas or in the U.S., or raise the cost of electricity to, or reduce the reliability of, electricity for consumers. The commenter stated that EPA's premise in the proposed Hg rule, was that it would preserve the ability to use all types of coal currently used in coal-fired EGUs. However, according to the commenter, the proposed rule did not support that premise because the proposed rule mandated Hg emissions reductions that would be technically impossible to achieve by certain EGUs burning certain types of coal and/or would be economically unreasonable for such EGUs. The commenter stated that, as a result, the proposed Hg rule would almost certainly prevent the continued use of certain types of coal as fuel in certain EGUs. The commenter asserted that this was especially true for Gulf Coast lignite, which would cease to be as viable as a fuel for EGUs, and might cease to be viable at all. The commenter stated that this negative impact of the proposed Hg rule would significantly harm fuel diversity, which would increase electricity prices and decrease electricity reliability without providing a commensurate health and environmental benefit.

Response:

EPA's modeling has shown little significant coal switching as a result of the proposed CAMR and CAIR actions. We do not believe that the final rules will have a negative impact on the nation's energy security, employment rates, or energy reliability. EPA does not feel that it is in the best interest of the country to prohibit the use of some ranks of coal when these coals can be adequately controlled to limit Hg emissions. EPA believes that a cap-and-trade approach will better serve to protect the environment while at the same time allowing the U.S. to maintain fuel diversity.

Comment:

One commenter (OAR-2002-0056-2523) stated that farmers should be considered an important stakeholder in any rulemaking which impacts the affordability and availability of electricity. The commenter stated that in 2002 the total energy consumed on U.S. farms exceeded 1.7 quadrillion Btu, with electricity accounting for almost 21 percent (356 trillion Btu) of that usage. Diesel and plant nutrients were said to be the only components of overall farm energy usage that exceeds that of electricity. According to the commenter, farmers spent $3.4 billion on electricity in 2002, and that amount would be significantly higher for 2004. (Electricity is used to irrigate 20 million acres in the U.S., more than diesel, propane and natural gas combined.) The commenter added that electricity is also used to milk cows, move grain, cool poultry houses, and light barns and homes as well as for many other critical functions. The

commenter supported cost-effective efforts to reduce Hg pollution because of reports that large doses of Hg can be harmful to people, especially children. The commenter, therefore, supported reductions in Hg emissions in rural areas and all across America. The commenter stated that, at the same time, farm families continue to be hit hard by fuel shortages and energy price increases. The commenter added that in just the last 12 months the availability and price of natural gas, diesel, gasoline, plant nutrients, propane and electricity have had a major impact on the farming community.

The commenter stated that farm groups have long supported multi-emissions legislation (based on an emissions trading program similar to that used successfully for SO_2 control), such as the proposal by Senator Voinovich that was before Congress. This legislation was predicted to cut power plant Hg emissions by nearly 70 percent by 2018. The commenter opposed any proposals that would force power plants to use expensive and unproven technologies. The commenter stated that imposing specific technologies and unrealistic deadlines on power plants could unnecessarily increase costs to utilities and electricity prices to consumers.

Response:

EPA believes that the final rule will address the concerns of the commenter. As noted earlier, EPA concurs with the commenter's concerns regarding the use of unproven technologies.

Comment:

One commenter (OAR-2002-0056-2422) stated that if EPA relies upon the Maximum Achievable Control Technology (MACT) provisions of CAA section 112, the Hg rule could be among the most costly regulatory mandates ever issued by the Agency. The commenter stated that reliance on an emission-trading alternative, with an emission cap and a more stringent ultimate level of control, may reduce overall compliance costs but introduce new compliance burdens, including constraints on the addition of new coal-based generating capacity. One of the commenter's principal concerns with this rulemaking was to ensure that new coal-fueled generating sources could be permitted in a timely and economic manner, consistent with the nation's needs for adequate and reliable electric power supplies, in full compliance with all applicable environmental safeguards.

Response:

EPA is finalizing a cap-and-trade program for Hg under section 111 of the CAA. The final CAMR is not projected to have any significant impact on the amount of new coal fired capacity projected in the power sector. The economic and energy impacts of CAIR are discussed in Chapter 7 of the RIA.

Comment:

Two commenters (OAR-2002-0056-1952, -2264) questioned the benefits to U.S.

residents of rule limiting U.S. emissions. Commenter OAR-2002-0056-1952 stated that if the cost of Hg removal drives U.S. electricity prices higher, we risk not only domestic job loss, but also substantially higher global emissions of Hg, sulfur, arsenic, NO_x, and CO_2. The commenter added that there are abundant worldwide resources of coal, and that there is no reason that coal-fired plants won't be built in developing countries where emissions control is not as important as jobs. The commenter expressed concern that an EPA policy intended to reduce global emissions may actually have the opposite effect by closing down U.S. plants with good controls and replacing them with offshore plants with no controls. The commenter recommended a goal-driven policy that sets targets for reducing Hg and CO_2 and allows market-place economics to select the successful technologies. Commenter OAR-2002-0056-2264 expressed concern about the cost/benefit of the proposed rule, and stated that the proposed rule would place the burden of global Hg emission reduction on U.S. coal-fired power plants. These domestic power plants were said to collectively represent less than 1 percent of the global emissions of Hg. The commenter stated that natural sources of Hg account for approximately two-thirds of global Hg emissions, with human sources accounting for the remaining third. The commenter claimed that recent analyses by the EPA and other experts found that as much as 70 percent of the Hg deposited in U.S. waterways comes from outside the U.S.

Response:

EPA is aware that global Hg emissions deposit in the U.S. However, as presented in the preamble to the final rule and elsewhere in this document, we believe that it is still prudent to regulate U.S. sources of Hg. We have discussed the impacts of global Hg emissions on the U.S. in the preamble and in various Technical Support Documents.

Comment:

One commenter (OAR-2002-0056-2883) believed that the EPA should consider the energy consequences (fuel supply), Unfunded Mandates and Regulatory Act and Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), and energy issues as outlined in EO 12866 consequences when promulgating the final rule to control Hg and nickel from utilities.

Response:

EPA has fully complied with all three EO during this rulemaking. An economic and energy impacts analysis, including analysis of the impacts of the rule on small entities and government owned entities, can be found in Chapter 7 of the RIA.

Comment:

Two commenters (OAR-2002-0056-2172, -2267) stated that EPA's Regulatory Impact Analysis failed to consider impacts on small entities as required by the Small Business Regulatory Fairness Act of 1996 (SBREFA). The commenters stated that Congress enacted SBREFA in order to protect small business, small organizations and small governmental jurisdictions, collectively referred to as "small entities," from disproportionate or unanticipated

adverse impacts of federal rulemaking activity, and that the analyses required by SBREFA must be undertaken prior to publication of any general notice of proposed rulemaking and must "contain a description of any significant alternatives to the proposed rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the proposed rule on small entities." 5 U.S.C. § 603(c).

Response:

EPA performed an analysis of the impacts of the proposed rule on small entities that was discussed in the January 30, 2004 Notice of Proposed Rulemaking (see 69 FR 4713). In the NPR, EPA certified that the proposed rule would not have a significant impact on a substantial number of small entities. For the final rule, EPA performed additional analysis of the impact of CAMR on small entities, which is included in Chapter 7 of the RIA.

Comment:

One commenter (OAR-2002-0056-2830) stated that EPA had underestimated the annual cost of monitoring, reporting and record keeping. The commenter stated that EPA had estimated the annual reporting costs to be $48.4 million, which equated to approximately $85,000 per unit. The commenter felt that this was an underestimate when the annual Hg compliance audit (which was budgeted at over $30,000 for a single annual audit) was considered. The commenter stated that the frequency of audits can be increased to semi-annual or more frequent, based on the monitor's performance. The commenter stated that, at present, there are no long-term Hg monitoring systems in-place at a coal-fired facility, that the current state of monitoring is very labor intensive and involves an extremely highly trained workforce, and that analyzers cost over $100,000. The commenter contended that EPA's estimate does not account for secondary systems required to support this equipment (e.g., monitor cabinets, air supplies, electrical power supply, electronic communication networks, data storage devices and software enhancements).

Response:

For the final rule, EPA has done an analysis of the cost associated with monitoring, reporting, and record keeping requirements for affected sources. EPA has estimated the annual costs associated with these activities to be about $76 million (see final CAMR preamble Section VI.B. Paperwork Reduction Act).

8.2 INDIAN TRIBES (CONSULTATIONS, UNIQUE IMPACTS AND RISKS)

Comment:

Three commenters (OAR-2002-0056-2380, -2695, -3413) criticized the cost-benefit analysis and risk assessment with respect to tribes. The commenters claimed that the models used to assess the impacts failed to independently address tribal lands, often establishing grids based on county boundaries that overlap tribal and State jurisdictions. The commenters requested that EPA develop a model that is appropriate for assessing the impacts of proposed

rules on Indian lands. The commenters also stated that the risk assessment models and cost benefit models did not account for unique tribal factors, such as subsistence and consumption levels. The commenters recommended a risk assessment model based on the precautionary principle, which properly accounts for tribal consumption levels. The commenters requested that EPA assess the risk for a period greater than 7 generations into the future relative to tribes that maintain subsistence lifestyles.

Comment:

Numerous commenters stated that high Hg levels in fish disproportionately affect Indian tribes because a number of power plants were located along the waterways that tribes directly used as food supply and that they consumed more fish than non-Indians (20 times that of the average American). The commenters asserted that EPA must assess the disproportionate health risk. Commenter OAR-2002-0056-4190 added that 5 pounds of fish were consumed per person per week in the commenter's tribe and that separate standards were needed to account for dietary differences among tribes. One commenter recommended that the final rule also address Indian Health Service findings on the disproportionate cardiovascular risk for Indians compared to national levels. The commenter stated that "hot spots" may increase cardiovascular risk in Indian people.

Comment:

One commenter (OAR-2002-0056-3457) stated that the discussion in EO 13175 is inadequate in that it only addresses compliance costs for two units in Indian Country, whereas Tribes are directly affected because of the effect on fishing and fish consumption in ceded territory inland waters and Lake Superior which adversely affect the practice of important cultural activities.

Comment:

Numerous commenters stated that EPA had not fulfilled its tribal consultation requirements under EO 13175 or EPA Indian Policy which required EPA to fulfill its trust responsibility to tribes and consult on a government-by-government basis. The commenters stated that consultation was inadequate given the significance of the rule, and because Indians were not included as stakeholders along with States. The commenters stated that this obligation is heightened by EO 12898 which established the Environmental Justice doctrine, and that these obligations required EPA to consult with the Tribes to determine how the proposed rule could result in heightened or unique impacts on Indian tribes. The commenters assert that after EPA has determined the unique impacts, EPA must then ensure that the rulemaking properly protects the tribes rights and resources. The commenters stated that EPA must identify and address disproportionately high human health and environmental effects on all tribes so that all people are equally protected from health and environmental hazards, and that EPA's proposals did not meet legal requirements, failed to protect public health and the environment (particularly with respect to the commenters), and created grave concerns about localized impacts.

Comment:

Two commenters (OAR-2002-0056-2380, -3413) stated that EPA must develop a proper tribal consultation strategy that ensures EPA will meet its trust responsibilities and conduct government-to-government consultations.

Response:

EPA recognizes that the Federal government stands in a government-to-government relationship with Federally recognized Tribes and ahs certain trust responsibilities to these Tribes. This relationship and responsibility should guide EPA in the implementation of policies and actions that affect Tribes. Pursuant to the government-to-government relationship, EPA consults with Tribes regarding actions that affect Tribes. In addition, treaties, statutes, and executive orders create Federal obligations regarding Tribal resources. EPA believes that its actions in developing the final rule have been consistent with the government-to-government relationship and that the final rule itself is consistent with the trust responsibility.

EPA does not agree with the commenters who claim that it did not consult with tribes in developing the rule. As explained in the discussion of EPA compliance with EO 13175 in the preamble for the final rule, EPA took the following steps to consult with Tribes. EPA gave a presentation to a national meeting of the National Tribal Environmental Council (NTEC) in April 2001, and encouraged Tribal input at an early stage. EPA then worked with NTEC to find a Tribal representative to participate in the workgroup developing the rule, and included a representative from the Navajo Nation as a member the official workgroup, with a representative from the Campo Band later added as an alternate. In March 2004, EPA provided a briefing for Tribal representatives, the newly formed National Tribal Air Association (NTAA), and NTEC. EPA received comments on this rule from a number of Tribes, and has taken those comments and other input from Tribal representatives into consideration in development of this rule.

EPA believes that this regulation adequately protects Tribal health and is consistent with the trust responsibility for several reasons. First, the commenters understate the significance of the fact that Hg emissions from Utility Units currently are not subject to performance standards. This regulation will for the first time establish performance standards applicable to Hg emissions, and those standards will require significant reductions in the levels of Hg emissions. Such reductions will provide greater protection to Tribal fish resources than would otherwise be available. Acting to provide such heightened protection is consistent with both the statute and the Federal trust responsibility.

Moreover, the commenters offer no specific evidence that the Hg emissions reductions from this regulation will not adequately protect Tribal health. Their main contention is that the regulatory approach set forth in an earlier EPA proposal would have produced a 90 percent reduction in Hg emissions and that any smaller reduction is, therefore, inadequate. That contention rests on a misconception of an earlier Federal Register Notice, which proposed a finding, but did not contain any specific proposal for Hg emissions regulations, and, therefore, did not provide for any percentage of reduction. EPA has never proposed any such rule. EPA believes that this regulation will adequately protect Tribal health.

The commenters also argue that EPA has not adequately considered the significance of Tribal fish consumption patterns, specifically the fact that Tribal fishers consume more fish than the general population. That comment is misplaced. As described in more detail elsewhere in this document, EPA carefully analyzed available information on fish consumption by Tribal members and other sub-populations, and determined how to use the available data most appropriately. One basis for EPA's analysis was a study of tribal fish consumption in one region to model consumption by other Tribes as well as other subpopulations. EPA's approach was to identify areas where the effects of Hg deposition from utility emissions had the greatest effects. EPA then compared those high-deposition areas with locations with high Tribal populations to assess the areas of greatest potential risk to Tribes. That analysis found very few areas where Native Americans live and there is high residual Hg deposition caused by utilities. Further, the analysis shows that the standards established in the regulation will significantly reduce risks to tribal members.

Finally, as discussed in the preamble to the regulation, this regulation establishes a cap-and-trade program for Indian country.

As part of its analysis of the final rule, EPA has estimated that some of the health benefits of reducing Hg from utilities. At this time EPA is only able to provide quantitative estimates of the benefits of reducing neurological impacts of exposure to MeHg for a portion of the U.S. population, women of child-bearing age. The RIA for this rule contains this analysis in Chapter 11. As part of its assessment, EPA provides estimates for the benefits of this rulemaking to subsistence fishers, including case study examples of the benefits to the some members of the Chippewa Tribe, the Hmong, and low income fishers.

8.3 FACA

Comment:

Many commenters criticized EPA's rulemaking process. Commenters claimed that many U.S. Senators and Congressmen asserted that EPA's actions may not be sufficient to meet procedural requirements under CAA section 307(d). The commenters criticized EPA for ending consultations with the FACA Committee, established in accordance with CAA section 117, and noted that, at the same time, EPA appeared to be disproportionately influenced by industry law firms.

Many commenters specifically criticized the rulemaking process for ignoring Agency scientists and FACA recommendations and not analyzing the range of controls recommended by FACA. The commenters pointed out that the EPA proposal was at odds with all FACA positions. The commenters claimed that EPA's actions showed complete disregard of a working partnership with States and other stakeholders, and noted that, at no time, was the possibility of a cap-and-trade program raised. Commenters believe that EPA should have consulted the States to address regional issues prior to making the alternative proposal. Commenter OAR-2002-0056-2886 found EPA's proposal a betrayal of the public stakeholder process. Commenter OAR-2002-0056-2819 specifically requested that EPA reconsider the NESCAUM and STAPPA/ALAPCO recommendations and incorporate them in the final rule. Commenter OAR-

2002-0056-3438 believed EPA's actions were a serious deviation from the rulemaking process and asked EPA to re-engage the advisory process that it abandoned.

Many commenters claimed the advisory group process confirmed that EPA conceded (1) it was legally required to adopt a MACT standard under section 112, (2) EPA had no authority to establish a cap-and-trade program to set a MACT floor for Hg, and (3) additional modeling needed to be done that apparently was never performed. The FACA co-chairman requested that all FACA work, as was documented on EPA's website, be entered into the docket. The FACA co-chairman also stated that EPA must produce the promised IPM modeling of the workgroup's final recommendations. The commenters stated that the IPM runs must be completed, made available to the workgroup, and entered into the docket. One commenter (OAR-2002-0056-2819) found EPA's refusals to perform the IPM modeling runs for the MACT proposal (without cap and trade) very troubling (these runs were requested by NESCAUM and STAPPA/ALAPCO during the FACA workgroup process). The commenter requested that EPA perform these runs before adopting a final rule using the recommendations submitted by the commenter. This commenter believed the results would confirm the superior environmental and health benefits cited by State and local agencies during the FACA process. The Massachusetts Attorney General submitted a Freedom of Information Act request regarding the modeling runs. Another commenter (OAR-2002-0056-2878) recommended that the modeling runs include high performing technologies and the IAQR co-benefits; failure to include the IAQR co-benefits would make the costs of Hg reductions artificially high. Three U.S. senators and one Congressman urged EPA to complete the analyses.

Comprehensive comments from public interest groups (OAR-2002-0056-3459) stated that EPA's complete disregard for the recommendations of the FACA Working Group convened for the MACT rule contravened CAA requirements and was arbitrary, capricious, and an abuse of discretion. The commenters noted that CAA section 117 required EPA to "to the maximum extent practicable within the time provided, consult with appropriate advisory committees" prior to publishing a 111 or 112 standard. The commenters added that "consult" meant to "consider" or "to seek information or advise from" and "to seek permission or approval from". The commenters submitted that EPA referenced its own working group only in passing and did not discuss its recommendations at all. These recommendations related to subcategorization, MACT floors, variability, format of the standard, monitoring, and regulation of nickel emissions from oil-fired units. In fact, the commenters claimed, a subset of the work group, including industry participants, reached agreement on the subcategorization issue and presented its consensus document to EPA. EPA's abrupt termination of the working group and its failure to evaluate their recommendations or even include them in the proposal at all did not, in the commenters view, comport with section 117(c) requirement to "consult". The commenters stated that EPA's subsequent proposal was weaker than any of the recommendations (including recommendations from industry stakeholders) of the work group members. EPA even refused to perform specific modeling runs to assess alternative MACT approaches requested by the work group.

One commenter (OAR-2002-0056-2519) stated that during the summer of 2002 EPA initiated the two-year process under the Clean Air Act Advisory Committee's Mercury Working Group, seeking stakeholder input to develop the Hg emissions control program. That process

considered various technical, policy and legal issues associated with setting the MACT standard. The commenter stated that at no time during those deliberations was there any suggestion to utilize a cap-and-trade program in lieu of MACT standards. Accordingly, there was no opportunity to fully assess and debate various issues associated with such a Hg emissions control approach. The commenter added that in December 2000, EPA made the regulatory determination that it was "necessary and appropriate" to regulate Hg emissions from the utility sector, triggering the process to establish MACT standards. The commenter believed that retracting that finding and establishing a cap-and-trade approach pursuant to CAA section 111 or 112 rendered the chosen program vulnerable to legal challenge.

Comment:

Four commenters (OAR-2002-0056-1479, -1658, -2364, -2819) requested that all FACA work, as is documented on EPA's website, be entered into the docket. The commenters stated that EPA must produce the promised IPM modeling of the workgroup's final recommendations and that the IPM runs must be completed, made available to the workgroup and entered into the docket. Commenter OAR-2002-0056-2819 stated that EPA's refusals to perform the IPM modeling runs for the MACT proposal (without cap-and-trade) was troubling, as these runs were requested by NESCAUM and STAPPA/ALAPCO during the FACA workgroup process. The commenter requested that EPA perform these runs before adopting a final rule based on recommendations submitted by the commenter. The commenter believed that the results would confirm the superior environmental and health benefits claimed by the State and local agencies during the FACA process.

Comment:

Four commenters (OAR-2002-0056-2364, -2010, -2012, -2015) requested that EPA provide modeling output. Commenter OAR-2002-0056-2364 stated that EPA must run the IPM at the control levels recommended by stakeholders in the workgroup (90 percent nationwide with at least 70 percent for each plant) to determine the optimal time for implementation. Three commenters (OAR-2002-0056-2010, -2012, -2015) recommended using time frames which match the times specified in EPA's section 111 proposal, and stated that running this analysis would satisfy the commitments EPA made to the workgroup.

Response:

Some of the issues raised by the commenters are the subject of on-going FOIA requests and pending litigation and, therefore, cannot be addressed here. EPA has placed all relevant materials in the rulemaking docket. EPA took into consideration the input from the workgroup. However, after over a year, EPA realized that consensus was not going to be reached in a timeframe consistent with our meeting our responsibility to propose a rule by December 15, 2003 and terminated the workgroup.

8.4 CHILDREN'S HEALTH (E.O. 13045)

28 Comment:

One commenter (OAR-2002-0056-2523) supported cost-effective efforts to reduce Hg pollution because of reports that large doses of Hg can be harmful to people, especially children. The commenter therefore supported reductions in Hg emissions in rural areas and all across America. The commenter stated that at the same time, farm families continue to be hit hard by fuel shortages and energy price increases.

Response:

EPA concurs that cost-effective approaches to reducing Hg emissions are most appropriate and believes that the cap-and-trade approach is the best approach.

Comment:

Comprehensive comments from a public interest group stated that EPA failed to meet the requirements of EO 13045 (Protection of Children from Environmental Health Risks and Safety Risks). The commenter stated that this failure is particularly egregious because EPA acknowledged that developing fetuses and children are at the highest risk with respect to Hg contamination. The commenter stated that the record showed that EPA changed the language from the Office of Management and Budget (OMB) package ("the order did not apply because the rule was based on control technology and not risk") to "the Agency evaluated the health and safety effects of the proposed rule and for the reasons explained above, the Agency believes the proposed strategies are preferable to other potentially effective and reasonably feasible alternatives." The commenter claims that the record demonstrates that EPA did not undertake such analysis, and it not only failed to do any analysis of the impacts of the proposed MACT or the section 111 cap and trade alternative on children's health, but also failed to conduct any analysis of the impacts compared to other approaches (potentially effective and reasonably feasible alternatives). The commenter stated that because of this failing, the proposed strategies can hardly be considered preferable [per section 5-501(b)] of the order. The commenter asserted that this is but one example of how EPA's language was changed to minimize the health risks of Hg exposure.

Response:

EPA has developed a more complete assessment of its regulatory approach as part of this final rulemaking action. The RIA which accompanies this rulemaking contains an assessment of the costs and benefits of the selected approach as well as regulatory alternatives.

As part of its analysis of the final rule, EPA has estimated that some of the health benefits of reducing Hg from utilities. At this time EPA is only able to provide quantitative estimates of the benefits of reducing IQ decrements associated with exposure to MeHg for a portion of the U.S. population, women of child-bearing age. The RIA for this rule contains this analysis in

Chapters 10 and 11.

Comment:

Numerous commenters stated that Hg poses a serious health threat to children and that EPA should elevate this issue in finalizing the rule. Many of these commenters specifically stated that EPA had not fulfilled its obligations for the protection of children's health under EO 13045 and had ignored recommendations of its own Children's Health Advisory Committee regarding Hg emissions from power plants (i.e., unique vulnerabilities of children, infants, and women of childbearing age were not adequately considered). One commenter (OAR-2002-0056-3322) questioned whether the current options go as far as possible and therefore requested more analysis. This commenter specifically called on EPA to: 1) Using existing information, evaluate the exposures and health risks to children and women of childbearing age, resulting from the proposed options, including how these might vary under the different options; 2) Evaluate the possibility of hot spots; and 3) Using existing information, conduct an integrated analysis of technologies, costs, health impacts, and economic benefits before choosing a regulatory option.

Commenter OAR-2002-0056-3543 questioned EPA's statement that the evaluation of the proposed strategies shows the rulemaking will improve air quality and children's health. The commenter stated that the link between air quality and children's health is water quality and fish contamination, and that therefore more than air quality needs to be evaluated to fulfill the requirements of EO 13045.

Response:

EPA has developed a more complete assessment of its regulatory approach as part of this final rulemaking action. The RIA which accompanies this rulemaking contains an assessment of the costs and benefits of the selected approach as well as regulatory alternatives.

As part of its analysis of the final rule, EPA has estimated that some of the health benefits of reducing Hg from utilities. At this time EPA is only able to provide quantitative estimates of the benefits of reducing IQ decrements associated with exposure to MeHg for a portion of the U.S. population, women of child-bearing age. The RIA for this rule contains this analysis in Chapters 10 and 11.

8.5 UNFUNDED MANDATES

Comment:

Two commenters (OAR-2002-0056-2172, -2267) stated that EPA's Regulatory Impact Analysis failed to fully consider the impacts of the proposal under UMRA, and that EPA also failed to provide a complete and accurate assessment of the anticipated impacts of the proposed rules pursuant to the UMRA, 2 U.S.C. § 1531 et seq. The commenters stated that EPA had concluded that the rules would not have disproportionate budgetary effects on any particular

local governments or types of communities. The commenters stated that the rule would, in fact, impose significant direct costs of compliance on the commenter's municipality; and would endanger the substantial investment that the municipality had in its electric generating facilities.

Response:

EPA performed an analysis of the economic impacts of CAMR on government-owned entities, which is summarized in Chapter 7 of the RIA. EPA has chosen to finalize a cap-and-trade program for Hg, which will reduce the economic impact of the rule on municipalities, through the flexibilities inherent in such a program.

Comment:

One commenter (OAR-2002-0056-2251) stated that under the Unfunded Mandates Act, EPA is required to examine how the proposed regulations to reduce Hg emissions would affect the nation's economy, with emphasis on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of U.S. goods and services. The commenter believed that regulations that reduce current coal-based electricity or impede construction of new coal-based power plants could damage our domestic economy. The commenter believed that all domestic energy resources will be needed to meet America's growing demand for reliable electricity. The commenter stated that, unlike natural gas, using coal and nuclear power (the principal alternatives to gas for generating baseload power) would not have a negative effect on other energy sectors that would impact consumers and businesses alike. The commenter believed that if EPA's rulemaking caused an even greater and faster shift away from coal to natural gas, the U.S. economy, along with millions of American workers and investors, would be hurt.

Response:

EPA provides an analysis of the economic and energy impacts of CAMR, including an economic analysis of the impacts of CAMR on small entities, in Chapter 7 of the RIA. Under CAMR, coal-fired generation and natural gas-fired generation are projected to remain relatively unchanged because of the phased-in nature of CAMR, which allows industry the appropriate amount of time to install the necessary pollution controls.

8.6 ENERGY EFFECTS

Comment:

One commenter (OAR-2002-0056-2850) with a high percentage of industrial customers who were high energy users struggling to compete in a competitive global market economy, recommended that any further emission reductions applicable to electric generating units (EGU) be implemented with reasonable time frames and cost to minimize the impact to residential and industrial customers alike.

Response:

The EPA believes that a carefully designed multipollutant approach – a program designed to control NOx, SO_2, and Hg at the same time – is the most effective way to reduce emissions from the power sector. One key feature of this approach is the interrelationship of the timing and cap levels for NOx, SO_2, and Hg. The recently finalized CAIR, combined with today's rule, will implement cap-and-trade programs for all three pollutants. The use of cap-and-trade will limit the costs of these rules relative to a command and control approach.

Comment:

One commenter (OAR-2002-0056-2334) recommended that the uncertainty of natural gas supply be considered to prevent shortages and rationing of natural gas. The commenter stated that current air regulation has driven electric utilities to use substantially larger amounts of natural gas, resulting in very high prices, and that, from 1992 to 2002 natural gas demand by the electric utility industry increased 60.5 percent and accounted for 93.6 percent of the nations' increase in natural gas demand (according to the EIA). The commenter recommended that the Ru1e be implemented in a manner that is "natural gas neutral." The commenter stated that the "46 month U.S. natural gas crisis" cost consumers over $130 billion and that air regulation played a significant role in that cost. The commenter recommended that the availability and reliability of natural gas supply be considered, as U.S. natural gas production has been flat for years. (Gas production in 1972 was 21,624 BCF and 19,047 BCF in 2002, a thirty-year time name. Gas production in 1998 was 19,024 BCF and 19,047 BCF in 2002, a five-year time frame.) Even with the current high rig count, production is flat to declining. The commenter stated that if electrical utilities continue to increase their use of natural gas, there is a real possibility of shortages and rationing of natural gas. The commenter stated that this would create an economic calamity that is avoidable through the increased use of available clean coal technologies.

The commenter stated that electric utility purchases of natural gas compete with all other consumers and have an unfair advantage, in that they have the ability to buy natural gas at any price and pass the cost on to the consumer. All other consumers such as manufacturing, home-owners and the farm community are price sensitive and given high prices would be required to make what the commenter felt were unnecessary sacrifices. The commenter stated that, in the past three years, 2.8 million manufacturing jobs have been lost in this country in large part due to the increased cost of energy and that further increases in energy cost would result in further loss of jobs.

Response:

EPA provides an analysis of the economic and energy impacts of CAMR in Chapter 7 of the RIA. Under CAMR, coal-fired generation and natural gas-fired generation are projected to remain relatively unchanged because of the phased-in nature of CAMR, which allows industry the appropriate amount of time to install the necessary pollution controls while still meeting our environmental goals. It should also be noted that, according to EO 13211: Actions that

Significantly Affect Energy Supply, Distribution, or Use, this rule is not significant, measured incrementally to CAIR, because it does not have a greater than a 1 percent impact on the cost of electricity production and it does not result in the retirement of greater than 500 MW of coal-fired generation. In fact, CAMR is not projected to result in any additional coal retirement relative to CAIR.

Comment:

One commenter (OAR-2002-0056-2251) believed that regulations that reduce current coal-based electricity or impede construction of new coal-based power plants could damage our domestic economy. The commenter believed that all domestic energy resources will be needed to meet America's growing demand for reliable electricity. The commenter stated that, unlike natural gas, using coal and nuclear power (the principal alternatives to gas for generating baseload power) would not have a negative effect on other energy sectors that would impact consumers and businesses alike. The commenter stated that if EPA's rulemaking caused an even greater and faster shift away from coal to natural gas, the U.S. economy, along with millions of American workers and investors, would be hurt.

Response:

The final CAMR is not projected to have any significant impact on the amount of new coal fired capacity projected in the power sector. Also, under CAMR, coal-fired generation and natural gas-fired generation are projected to remain relatively unchanged because of the phased-in nature of CAMR, which allows industry the appropriate amount of time to install the necessary pollution controls. The economic and energy impacts of CAIR are discussed in Chapter 7 of the RIA.

Comment:

Two commenters (OAR-2002-0056-2066, -2334) requested energy studies. One commenter (OAR-2002-0056-2334) stated that it is essential that a new study be completed by the EIA to determine the impact of this rule on natural gas demand and price under EO 13211. The commenter asserted that consumers need assurances that the way the EPA plans to implement the rule will not increase demand for natural gas. Commenter OAR-2002-0056-2066 stated that in May 2001, EO 13211 was signed by the President and noted that, with the full understanding that Federal Government regulations "can significantly affect the supply, distribution, and use of energy," the President, through EO 13211, requires agencies to prepare a "Statement of Energy Effects" when undertaking certain actions. The commenter asserted that EPA's proposal on regulation of Hg emissions from electric utility steam-generating units fell within the intent of the President's issuance of this order as well as within the parameters outlined in the order itself. The commenter urged the EPA to undertake such a study in full compliance with the EO, and if it has already done so, the commenter requested that the document be published for public review and comment.

Response:

EPA has fully complied with EO 13211 in this rulemaking. A complete economic and energy impacts analysis is provided in Chapter 7 of the RIA.

8.7 ENVIRONMENTAL JUSTICE

Comment:

Numerous commenters stated that EPA must assess the environmental justice implications of the proposals. Commenters stated that there are environmental justice problems because impact of lax controls fall on native people and African-Americans who consume more fish than the rest of the population and poor inner city residents, including children, who reside near multiple Hg emission sources. Commenters recommended that EPA also identify and analyze the issue of disproportionate public health risk to populations that subsist on Hg-contaminated fish and shellfish in the context of the trading proposal, as required under EO 12890. Commenter OAR-2002-0056-3396 emphasized the disproportionate impacts on pregnant women, unborn children, and children from poor families.

Response:

EPA has developed a more complete assessment of its regulatory approach as part of this final rulemaking action. The RIA which accompanies this rulemaking contains an assessment of the costs and benefits of the selected approach as well as regulatory alternatives.

As part of its analysis of the final rule, EPA has estimated that some of the health benefits of reducing Hg from utilities. At this time EPA is only able to provide quantitative estimates of the benefits of reducing IQ decrements associated with exposure to MeHg for a portion of the U.S. population, women of child-bearing age. The RIA for this rule contains this analysis in Chapters 10 and 11. As part of its assessment, EPA provides estimates for the benefits of this rulemaking to subsistence fishers, including case study examples of the benefits to the some members of the Chippewa Tribe, the Hmong, and low income fishers.

8.8 DATA QUALITY

Comment:

One commenter (OAR-2002-0056-2422) stated that Congress enacted new data quality legislation as part of the FY2001 Consolidated Appropriations Act (P.L. 106-554, §515) which expanded previous data quality report language in the FY 1999 Omnibus Appropriations Act (P.L. 105-277). The commenter stated that in response to these Congressional directives, the OMB had developed government-wide standards for the quality of information used and disseminated by Federal agencies, including EPA. The commenter stated that OMB's "Information Quality Guidelines (October 1, 2002)" set forth the government-wide guidelines for "ensuring and maximizing the quality, objectivity, utility and integrity of information

disseminated by Federal agencies." The commenter quoted the guidelines as "Objectivity is a measure of whether disseminated information is accurate, reliable and unbiased, and whether that information is presented in an accurate, clear, complete and unbiased manner." The commenter noted concern about the objectivity of EPA's Hg MACT determination process, including but not limited to the selection of the plants included in EPA's ICR data base and the what the commenter claimed was EPA's mischaracterization of coal supplies to the top-performing units selected for MACT floor evaluations. The commenter felt that EPA's sample of 80 plants appeared to be deliberately skewed toward certain plant configurations employing advanced control technologies, and thus was not representative of the entire population of coal-fired boilers in the U.S. The commenter state that concerns on this point were raised in the EPA Mercury MACT Working Group process, without apparent response by EPA. The commenter opposed MACT-based Hg regulation for coal-fired electric generating units.

Response:

EPA is not finalizing a MACT rule for Hg, but rather, a cap-and-trade program under section 111 of the CAA.

RESPONSE TO SIGNIFICANT PUBLIC COMMENTS ON THE PROPOSED CLEAN AIR MERCURY RULE

Received in response to:

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 4652; January 30, 2004)

Supplemental Notice for the Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 12398; March 16, 2004)

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources, Electric Utility Steam Generating Units: Notice of Data Availability
(69 FR 69864; December 1, 2004)

Docket Number OAR-2002-0056

9.0 NODA Comments

US Environmental Protection Agency
Emissions Standards Division
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

15 March 2005

General Outline

9.0 NODA COMMENTS

A. Electric Power Sector Modeling

General Comments concerning Electric Power Sector Modeling

Comment:

One commenter (OAR-2002-0056-5469) noted that the EPA NODA provides what is stated as a summary of the model results reported by CRA in comments submitted by both the commenter and EPRI in June 2004. In presenting its summary (Table 4 of the NODA), EPA chose to report the EPMM emissions estimated for 2018-2019 as if they were the 2020 emissions estimate too. This is incorrect, and hides the fact that EPMM scenarios projected that Hg emissions would fall to 15 tons by 2020. It is extraordinary that EPA would choose to state a completely different number in the summary table than was reported by the original investigators, even if EPA had reason to dispute the basis for the finding of the original investigators. Nevertheless, even the rationale EPA provides for listing a very different emissions result than was originally reported is wrong and reflects a misunderstanding of how optimizing models function.

> The NODA states:
> "EPA notes the commenter's projected emissions of 15 tons in 2020 appear to be an artifact of the grouping of the 2020 run year with the model end run year of 2040. EPA maintains that, in a leastcost solution model like EPMM, the model would solve for the cap in the final run year grouping. Therefore, Hg emissions reported for trading scenarios in the table below [i.e., Table 4 of the NODA] are those projected for 2019, because EPA believes they better represent emissions in 2020."

The commenter further stated that it is not true that optimizing models like EPMM force emissions to reach the cap in their end year. Optimization does require that there be zero banked emissions at the end of the model horizon, but it is perfectly possible to enter the last modeled period (i.e., 2020-39 in this case) with a positive bank balance. If this happens, then the model will select just enough controls for that last period so that emissions will last exactly the length of the last period, and be exactly exhausted at the *end* of the terminal modeled period. For example, if the last modeled period is 10 years long, a least-cost solution might be to enter that last 10-year period with 10 tons in the bank, which would be used up at the rate of 1 ton per year. Controls would be applied at the beginning of the terminal period to bring emissions to exactly 1 ton above the final level of the cap. At the end of the 10 years, emissions would have to be reduced to exactly the level of the cap. Thus, when the model says emissions are exactly at the cap at the beginning of the terminal period, this is because achieving the cap by that first year (rather than by the last year of that period) is lower-cost than the only alternative, which would be to make yet greater reductions in one or more of the earlier periods that would enable entry into the terminal period with a positive bank-balance.

The commenter also noted that another way to state this is that emissions cannot be above the final level of the cap (15 tons in this case) during *any year* of the terminal period unless there is a positive balance of banked emissions at the end of the year just prior to the start of the terminal period. This provides yet another way to demonstrate that EPA is wrong when it states that emissions in 2020 would be closer to the level projected for 2019 than to 15 tons. Table 1 shows the emissions projected in each modeled period of EPMM for the base Hg cap scenario, and the level of the cap that applies in each time period. The last column shows the resulting balance in the Hg allowance bank at the end of each of the modeled periods. It is quite clear that if emissions follow the path selected for each of the modeled periods prior to the terminal period of 2020, then there will be no allowances in the bank at the start of 2020, and emissions must be 15 tons from 2020 onwards. This is not an "artifact" of the fact that 2020 is the first year of the terminal model period.

Table 1. Bank Balances Under EPMM Scenario for Proposed Mercury Cap*

Year	Hg Emissions (tons per year)	Hg Cap in Same Time Period (tons per year)	Annual Rate of Accumulation in the Bank (tons per year)	Hg Bank at Beginning of Period (tons)
2004-2007	44.6	na	na	na
2008-2009	43.3	na	na	na
2010-2011	34.0	34.0	0.0	0.0
2012-2014	32.2	34.0	+1.8	0.0
2015-2017	29.9	34.0	+4.1	5.3
2018-2019	23.9	15.0	-8.9	17.7
2020-2039	15.0	15.0	0.0	0.0

* Values in Table 1 are from the scenario that applies no reduction in variable O&M costs of ACI, i.e., the standard case in Table 4 of NODA. Results are comparable for all the other EPMM cap-and-trade scenarios reported in NODA.

It is therefore impossible to reconcile the emissions and control actions that the model selects from 2004-2018 with any emissions level other than 15 tons starting in 2020 (and, of course, lasting at 15 tons thereafter). If emissions in 2020 were to be 24 tons, as EPA has incorrectly asserted, then the bank would have to be drawn down to negative 9 tons in 2020 alone. This is not how EPMM works. If EPMM were to find it cost-effective to delay compliance with the cap beyond 2020, it would have to reduce emissions by much larger amounts prior to 2020. It has the option to do this, but the model chooses not to. The model finds that a time path of emissions that entails reaching exactly 15 tons by the beginning of 2020 is the least-cost solution. This may not be consistent with EPA's IPM results, but the commenter's June 2004 submission (see OAR-2002-0056-2929) provides an extensive explanation of the differences in our and EPA's model assumptions that explain that difference.

Since the preceding explanation may be difficult for non-specialists to follow, it is useful to demonstrate that EPA is in error by employing evidence in the model runs themselves. Table 2 lists the SO_2 emissions that were reported for the same scenario, along with the caps applied.

As in Table 1, the last column shows the banked allowances (which include the amount assumed to be in the Title IV bank just before the beginning of the first modeled year, 2004). The emissions of SO_2 do not exactly meet the SO_2 cap at the beginning of 2020, as they do in the same model run for Hg (Table 1). Entering the terminal period of 2020-2039, there are 769,644 tons of SO_2 in the bank. As the model does force this bank to be exactly used up by the end of that terminal period, and at a constant level throughout that period, emissions exceeds the cap by exactly 769,644/20 tons (i.e., by 38,482 tons) in 2020 and in each of the next 20 years. Thus, a counterexample exists in the very same model runs that EPA was summarizing to EPA's assertion that "the model would solve for the cap in the final run year grouping".

Table 2. SO_2 Emissions and Bank Balances Under EPMM Scenario for Proposed Mercury Cap*

Year	SO_2 Emissions (tons per year)	SO_2 Cap in Same Time Period (tons per year)	Annual Rate of Accumulation in the Bank (tons per year)	SO_2 Bank at Beginning of Period (tons)
2004-2007	9,340,664	9,480,000	139,336	8,000,000
2008-2009	8,100,088	9,480,000	1,379,912	8,557,344
2010-2011	6,071,281	5,086,400	-984,881	1l,317,168
2012-2014	5,552,485	5,086,400	-466,085	9,347,406
2015-2017	4.476,623	3,798,600	-1,678,023	7,949,151
2018-2019	4,871 ,319	3,798,600	-1,072,719	2,915,082
2020-2039	3,837,082	3,798,600	-38,482	769,644

* Values in Table 2 are from the scenario that applies no reduction in variable O&M costs of ACI, *i.e.*, the standard case in Table 4 of NODA. Results are comparable for all the other EPMM cap-and trade scenarios reported in NODA; we use this case here because it is one for which SO_2 emissions were reported in our earlier submissions, and which EPA therefore had the ability to review.

Nevertheless, there are some good reasons to de-emphasize reported model results associated with the terminal model period of models such as EPMM and IPM. CRA did not choose the time periods in EPMM with the goal of being able to report precise estimates of emissions specifically for 2020, nor even with an expectation that any year after 2018 would have any interest. Given that substantial emphasis has since been focused on whether the Phase II Hg cap of 15 tons might be fully attained by about 2020, the commenter felt it is reasonable to allow a time step for 2020 that is not the terminal time period of the EPMM model. Since release of the NODA, the commenter added another time step to EPMM that starts in 2030 and represents the final 20-year period (through 2049). Results for the 2030 terminal time step can be de-emphasized without losing information about the likely emissions in the 2020 time frame.

The commenter ran the extended-horizon version of EPMM for the same Hg cap-and-trade assumptions that were reported in the NODA Table 4 as with "improved ACI costs." Table 3 provides the emissions values from the original run when 2020 was the beginning of the terminal model period, and from the new run which differs only in that 2030 is now the beginning of the terminal model period. These emissions paths are illustrated in Figure 1. The

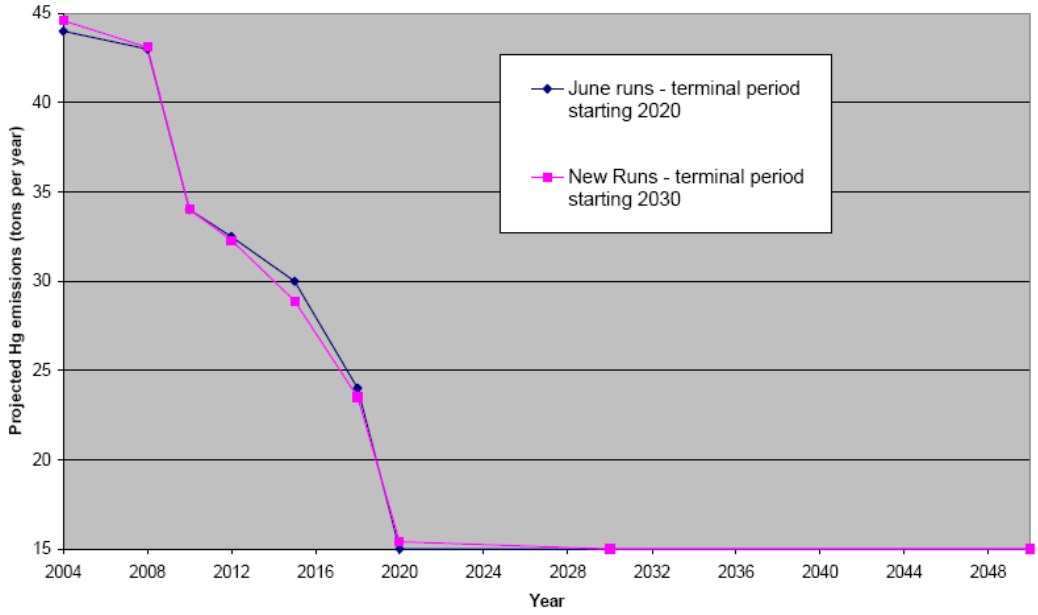
emissions paths are very similar. Most importantly, emissions in 2020, even when it is not a terminal period of the model), are still very close to the final cap of 15 tons (i.e., they are 15.4 tons). Results using a version of EPMM where 2020 is not the terminal period further demonstrate that EPA was not justified in replacing our reported 2020 emissions values on an ad hoc basis with our reported 2019 emissions level.

All the available models (EPMM and IPM alike) provide only an approximation of what are emissions paths continuously changing in time because they are forced by computational resources to simulate discrete multi-year time steps rather than the more realistic path of gradual year-over-year emissions reductions. The actual optimal time path of emissions will be smoother, and this means that emissions in 2020 might be somewhat higher than in 2021, and in each of the remaining years in the 2020 time period. However, one must recall that the requirement of a non-negative bank of Hg allowances imposes an important constraint on emissions after 2018. For example, the EPMM model indicates that emissions in 2020-2029 would be a constant 15.4 tons. The bank going into that time period is 3.6 tons. Thus, even if (both cases simulate the proposed Hg cap-and-trade scenario and assume a 2.5 percent per annum reduction in variable O and M cost of ACI control technologies)

Table 3. Hg Emissions Projections Differing Terminal Model Periods

	Terminal period starting 2020 (June submission)	Terminal period starting 2030 (This submission)
2004	44.4	44.6
2008	43.2	43.1
2010	34.0	34.0
2012	32.6	32.3
2015	29.4	28.9
2018	24.1	23.5
2020	15.0	15.4
2030	15.0	15.0

Figure 1. Hg Emissions Projections from EPMM with Terminal Model Periods Starting in 2020 versus 2030



emissions in 2020 were to remain above emissions in following years of the 2020-2029 time step, those 2020 emissions could not exceed 18.6 tons (i.e., 3.6 tons above the cap). Further, if they were that high in 2020, then the 15 ton cap would have to be met exactly from 2021 onwards. In other words, although ad hoc reasoning could lead one to conclude that 2020 emissions might be as high as 18.6 tons, such ad hoc reasoning must also accept that emissions only one year later (i.e., from 2021 onwards) must meet the Phase II cap.

Thus, modeling based on the assumptions the commenter documented in June 2004 (see OAR-2002-0056-2929) indicates that either the Phase II cap will be met within all but a fraction of a ton by 2020, or if it is exceeded by any significant amount in 2020, then it will be exactly attained within one or two years after that.

Response:

Based on the commenter's additional analysis submitted into the record, EPA agrees that commenter's analysis projected emissions to be 15.4 tons in 2020 for the modeled Hg trading scenario. However, we disagree with the commenter's conclusion that we misunderstand how optimizing models function. In the NODA in which EPA summarized the commenter's analysis submitted to the record, EPA did not state optimizing models like EPMM force emissions to reach the cap in their end year, rather we stated that optimizing models solve for the cap. That is to say, we agree with the commenter statement that optimization does require that there be zero banked emissions at the end of the model horizon, i.e, solve for the cap. EPA also agrees with the commenter that it is possible to enter the last modeled period (i.e., 2020-39 in this case)

with a positive bank balance. EPA anticipated a more gradual withdrawal of the bank given that additional Hg controls are being installed in the 2018-2019 timeframe. This is similar to what EPA sees in it own modeling and what the commenter is projecting in its SO_2 modeling. However, EPA does not dispute the additional data the commenter submitted on the bank withdrawal in its modeling.

Comment:

One commenter (OAR-2002-0056-5469) stated that there is only one possible reason why bank-balance accounting may not be applicable to the argument above: the so-called "safety valve." The concept of the "safety valve" is originally one of providing a formal, legislated ceiling on allowance prices. It was first introduced in carbon policy proposals. EPA's proposed rule includes a concept that EPA calls a "safety valve," but which would not be implemented in the manner necessary for it to function as a price ceiling. In EPA's proposed cap-and-trade rule in the Clean Air Mercury Rule (CAMR), companies may "borrow" against their own future allocations of Hg allowances if prices exceed some pre-specified amount. Borrowing against one's future fixed allocation is a substantially different matter than having the government issuing as many additional allowances as might be demanded for a fixed price. The former maintains the constraint of the cap unchanged across a set of years, whereas the latter actually loosens the cap. The former creates far less flexibility, because by reining in allowance prices in one year, it only increases allowance prices (by reducing available allowances) in a later year. In all, the concept that EPA calls a "safety valve" in its proposed rule is not a price cap at all. More importantly, it retains a binding constraint on cumulative Hg emissions, regardless of the possible future marginal cost of meeting that cumulative constraint. Thus, it remains correct for a discussion about the future time path of emissions under the Hg cap-and-trade proposal to assume that sustained negative bank balances are not cost-effective.

Response:

EPA is not finalizing a safety valve provision in the cap-an-trade rulemaking. See final rule preamble for further rationale.

Comment:

One commenter (OAR-2002-0056-5469) noted that the NODA states that the commenter's/EPRI scenarios were not performed with a safety valve. First, to the extent that the cumulative cap remains inviolate, as described in the formal EPA proposal, the scenarios do approximate its effect. Second, even if one were to assume a safety valve that could be interpreted as a literal cap on Hg prices, that safety valve would not be exceeded in any scenario the commenter ran except the one assuming no cost reduction on Hg control technology at all during the next 15 years. Thus, CRA's runs and results are consistent with even a true safety valve implementation. Nevertheless, merely having the ability to borrow against one's own future fixed allocation would not place a ceiling on allowance prices.

Response:

EPA agrees with the commenter.

Comment:

One commenter (OAR-2002-0056-5469) noted that the NODA also understates the degree of attention that CRA's analysis gave to alternative possible rates of technological improvement. EPA implies at p. 69869 of the NODA that CRA's analysis included only two alternative assumptions about the rate of technological improvement, (i.e., 2.5 percent annual reduction in variable O&M costs and 0 percent). In fact, CRA considered five different sets of assumptions about potential technological improvements, including none at all, and varying rates of future reductions in variable O&M costs, and in capital costs as well as O&M costs. All of these alternatives were presented as a set, to emphasize that the commenter were not advocating any single assumption, but only to convey the insight that technological improvement would have an effect on projected allowance prices (while having little or no impact on other aspects of the policy).

Response:

EPA was aware of the commenter other analyses, but limited the presentation of analysis to those that offered comparisons to other commenter's analyses. EPA has considered all the information submitted by the commenter in the final rulemaking.

Comment:

One commenter (OAR-2002-0056-5469) noted that in OAR-2002-0056-2578, EPRI reported on deposition patterns for 2020 that were developed with the TEAM model using unit-specific emissions projections from the EPMM model. The deposition pattern for the 15 ton cap-and-trade scenario indicated larger deposition reductions than the MACT scenario in all regions. It projected the largest deposition reductions concentrated in the area of the Ohio River Valley and Middle Atlantic States, which had moderately high projected deposition under base case conditions. These results suggested that there was no reason to conclude that the cap-and-trade policy option might create hypothetical "hot spots," or allow hypothetically existing "hot spots" to continue where the MACT policy option would not.

Nevertheless, EPA continues to express concerns with the possibility of hypothetical "hot spots" persisting under a cap-and-trade program. In particular, there have been suggestions that despite projections of broad regional reductions in deposition, there might still be a few individual plants that are large emitters that might not individually control Hg emissions, and which could pose a "hot-spot" concern. CRA has prepared a more detailed summary of the plant-by-plant emissions changes in its originally-reported Hg cap-and-trade scenario. The commenter took the unit-specific emissions for 2004 and 2020, and aggregated them to obtain plant-wide emissions, which best represent the size of an individual utility point-source. The results of this detailed review of the earlier EPMM results are summarized in Figure 2.

In Figure 2, each dot represents one of the 401 coal plants in the modeled data base. They are located on the x-axis according to the projected 2004 emissions (in kg/yr). The highest emitting plants are those on the right side of the plot. (If the emissions of each dot are summed up, the total is equal to EPMM's estimated reference case US utility sector Hg emissions in 2004: 47 tons, or 42,800 kg.) The y-axis reveals the percent Hg reduction at each plant by 2020

in the cap-and-trade scenario, when total emissions are reduced to 15 tons, or 13,636 kg. This figure provides a way of screening for plants that might pose a potential concern under a cap-and-trade program for hypothesized "hot spots." That is, the likeliest plants of concern would be those that are large emitters, but which either fail to control, or increase their emissions as a result of the flexibility provided by cap-and-trade.

The set of plants that emit more than 100 kg/yr (i.e., more than 220 lb/yr) are those in the pink triangular area of Figure 2. This set contains 37 percent of all plants (150 plants), and accounts for about 75 percent of total US emissions projected in the 2004 base year. All plants but one in this group reduce their plant-wide emissions by at least 20 percent, and most by over 60 percent; in fact, the average projected reduction of these top 150 plants is 76 percent.

The single plant that does not reduce its emissions is a lignite-burning plant that already has a fabric filter and wet FGD. The lignite that it uses has a relatively low Hg content. When these attributes are combined with our assumption that ACI only reduces remaining Hg by 75 percent in a lignite plant, this plant faces a very high dollar-per-ton removal–much higher than that projected as the marginal cost of control in the Hg allowance market when the cap has reached 15 tons. Thus, this single plant among all the top 150 emitters relies solely on allowance purchases in response to the 15 ton cap. It is noteworthy that this plant is projected to emit the same quantity of Hg under the proposed MACT policy option as well, because its estimated current emissions rate meets the MACT rate limit proposed for lignite plants.

Conclusions are much the same even when we consider all plants emitting more than 50 kg/yr (i.e., more than 110 lb/yr). This set of plants includes 89 more plants that emit between 50 and 100 kg/yr (all the dots within the green rectangular area of Figure 2) as well as the 150 plants emitting more than 100 kg/yr considered in the preceding paragraph (the dots in the pink area). This larger group of 239 plants accounts for 60 percent of all plants in the model database, and as a set, they are projected to account for 90 percent of all US utility emissions in the 2004 base year. (Otherwise stated, all the remaining plants account for only 10 percent of US emissions.)

Even when accounting for the largest-emitting plants that emit 90 percent of all utility emissions, almost all are projected to control their emissions. The average reduction within this larger set is 74 percent. As can be seen in Figure 2, there are only 6 plants within this set of 239 plants that do not have a financial incentive to choose to reduce their emissions in the face of a 15 ton cap on utility emissions. Only one of the 6 is among the top 150 plants, and it was discussed above. Of the other five:

- Two are lignite plants identical in configuration to the one described above, emitting primarily elemental Hg (Hg^0). These two plants also have the same projected emissions under the MACT option as under the cap-and-trade option.

- There are two plants that are projected to have a slight increase in their emissions by 2020. Both of these already have a wet FGD and SCR on a cold-side ESP unit. As they burn a bituminous coal, they are assumed to obtain very large percentage reductions (i.e., 85 percent) due to the existing pollution control equipment in place. Thus, these plants face relatively high dollars-per-ton removed from their only remaining control option,

which is to add ACI. The slight increase in Hg emissions results when these plants switch from a high-sulfur coal to a blend with a medium-sulfur coal (in order to further reduce their SO_2 emissions as the price of SO_2 rises). Small increases in emissions like this are more likely to occur on plants that already have the highest levels of co-controls. More importantly, however, is that these two plants also increase their emissions under the MACT option. That is, their current emissions rate is already below the 2.0 lb/tBtu limit required by the proposed MACT option, and these plants have even less financial incentive to avoid minor Hg emissions increases under the MACT option than under the cap-and-trade option. (EPRI's comments on the NODA explore the local deposition implications of the Hg emissions at these two plants. EPRI's comments report that the projected local deposition around these two plants actually decreases in 2020 despite the slight increase projected from these plants individually. This is because there is so much other control being applied to the many coal-fired sources that surround these plants, which are located in ECAR, and those other sources also affect deposition projected within the respective 20 km squares where these plants are located.)

- The fifth plant is the lowest emitter among those that do not change their Hg emissions at all. This plant has an existing fabric filter and wet FGD. This is a western plant burning a blend of western bituminous and subbituminous coal. Being a western plant, it has no incentive to add an SCR other than from Hg co-benefits, but those are low due to its use of subbituminous coal. Being highly controlled already, it is also a relatively costly candidate for ACI compared to other plants in the system. Like the three lignite plants, this unit already meets its MACT standard, and so its emissions are also unchanged under the MACT option.

Response:

EPA generally agrees with the commenter that cap and trade is not expected to lead to hotspots. EPA has done extensive power sector, air quality, deposition, and ecosystem modeling. See the preamble for the rule and the Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls in the docket.

Comment:

The commenter (OAR-2002-0056-5460) stated that rather than providing a balanced account of the comments EPA has received to date, the NODA instead appears to endorse those comments that call for weaker regulations. The commenter further stated that this aspect of the NODA is most clearly apparent in EPA's contrasting treatment of the comments received from the Center for Clean Air Policy (CCAP) and Cinergy concerning the costs of complying with various regulatory approaches. See 69 Fed. Reg. at 69,867-69,868. The commenter stated that according to the NODA, CCAP and Cinergy reached contrasting conclusions concerning the costs and burdens associated with the CAMR. The commenter added that specifically, CCAP concluded that EPA could impose even stricter requirements with relatively modest cost implications, while Cinergy concluded that EPA's existing proposal, to say nothing of stricter regulations, was already "unrealistic." See 69 Fed. Reg. at 69,867-69,868. The commenter stated that rather than describing those contrasting conclusions in a balanced manner, EPA

instead appears to endorse Cinergy's conclusion. The commenter stated that the NODA states that CCAP's conclusion is CCAP's "opinion" but includes no such disclaimer for Cinergy's conclusion. Compare 69 Fed. Reg. at 69,867 (3d Column) with 69 Fed. Reg. at 69,868 (3d Column). The commenter further stated that EPA also appears to accept at face value Cinergy's self-serving assertion that a MACT standard of 0.88 lbs/TBtu is "stringent." 69 Fed. Reg. at 69,868 (1st Column). According to the commenter, such a standard is approximately four times weaker than the standard that EPA should impose absent subcategorization by coal rank. See Multistate Comments at 22 (explaining that EPA could set a MACT standard of 0.2 lbs/TBtu, absent subcategorization); see also id. at A12-13 (discussing the MACT standards that should be imposed if EPA subcategorizes). The commenter stated that in these circumstances, and in light of its treatment of CCAP's conclusions, the NODA should have clarified that it is simply Cinergy's "opinion" that a standard of 0.88 lbs/TBtu is stringent. But, the commenter stated, the NODA contains no such explanation and Cinergy's own comments (see OAR-2002-0056-4318) provide no reason to accept Cinergy's assertion as fact.

The commenter stated that EPA should not have used the NODA to present an unbalanced description of the comments received in response to the proposed CAMR. In addition, the commenter also objected to EPA's failure to provide sufficient information about the power sector modeling runs it has conducted. The commenter noted that On March 19, 2004, Massachusetts Attorney General Thomas F. Reilly submitted a public record request to EPA regarding its Integrated Planning Model (IPM) runs. The commenter further noted that in response, EPA has withheld hundreds of documents alleging that they fall within Exemption 5 of the Freedom of Information Act. See Exhibit B (Letter from Byron R. Brown, Assistant General Counsel, EPA, to James R. Milkey dated December 9, 2004). (See OAR-2002-0056-5460.) The commenter stated that, significantly, several of the documents EPA is withholding appear to contain factual information bearing directly on the NODA's discussion of power sector modeling (and may be relevant to the CAMR for other reasons as well). The commenter further stated that EPA's failure to make those documents available to the public in the CAMR docket is problematic for the following reasons: First, if EPA has ignored the documents, it may have acted in an arbitrary and capricious manner in developing the CAMR. The commenter stated that, alternatively, if it has considered the documents, its failure to make the documents available for public review and comment may violate both the Clean Air Act and the Administrative Procedure Act. See 42 U.S.C. § 7607(d)(3) ("All data, information, and documents. . . on which the proposed rule relies shall be included in the docket. . ."); Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 393 (D.C. Cir. 1973) ("It is not consonant with the purpose of a rule-making proceeding to promulgate rules on the basis of inadequate data, or on data that, [to a] critical degree, is known only to the agency.") The commenter stated that, accordingly, EPA should make the documents available in the CAMR docket and should explain how, if at all, it has used the documents in developing and proposing the CAMR.

Response:

EPA's presentation of summaries of the commenters data was not meant as an endorsement to any of the commenters data. EPA will address the commenters concerns related to document availability in the FOIA process.

Comment:

The commenter (OAR-2002-0056-5460) noted that EPA contends that power sector modeling is relevant to its obligation under Section 112 of the Clean Air Act to set beyond-the-floor standards based on an analysis of cost, non-air quality health and environmental impacts and energy impacts. See 69 FR at 69,866 (2nd column). But, the commenter stated, the NODA does not adequately explain how power sector modeling is relevant to assessing non-air quality health impacts, non-air quality environmental impacts or energy impacts. The commenter further stated that, indeed, the NODA's focus on comments concerning the alleged cost of certain control measures creates the impression that power sector modeling is relevant solely to cost. Therefore, the commenter reiterated that EPA is required to also consider non-air quality health and environmental impacts in setting beyond-the-floor standards pursuant to Section 112.

The commenter stated that it also bears emphasis that industry commenters have an incentive to overstate the costs of complying with environmental regulations. The commenter further stated that, indeed, various studies have suggested that the costs of complying with environmental regulations are usually less than what industry commenters estimated in advance. The commenter added that, accordingly, EPA should look skeptically upon industry cost estimates. The commenter stated that one reason industry cost estimates may be too high is the failure to anticipate technological innovations that regulations will inspire. For a fuller discussion of this issue, the commenter referred EPA to the CAMR comments of the Northeast States for Coordinated Air Use Management (NESCAUM), OAR-2002-0056-2888, and to NESCAUM's September 2000 report entitled Environmental Regulation and Technology Innovation: Controlling Mercury Emissions from Coal-Fired Boilers, a copy of which is attached as Exhibit D (See OAR-2002-0056-5460).

Response:

EPA's approach for the final rulemaking is to establish Hg reductions under section 111 cap through a cap-and-trade mechanism. EPA agrees with the commenter that technology innovation is likely to reduce future control costs. To that end, EPA has included the examination of technology improvement in its analysis of the costs of the rulemaking. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis.

Comment:

The commenter (OAR-2002-0056-5460) stated that none of the information that EPA has requested is relevant to determining the proper MACT floor under Section 112 of the Clean Air Act–a fact that EPA itself appears to recognize. See 69 Fed. Reg. 69,864-69,866 (2nd column) (explaining why EPA believes the information it seeks concerning power sector modeling and Hg speciation is relevant), id. at 69,872 (2nd Column) (same for the information EPA seeks concerning its proposed revised benefits assessment methodology). The commenter stated that, thus, the NODA does not address one of the most fundamental defects in the CAMR. The commenter further stated that, indeed, the NODA does not even mention the MACT floor issue. The commenter stated that by omitting mention of that issue, EPA has presented an incomplete account of the issues raised in the CAMR comments. The commenter also stated that in

addition, until EPA calculates a proper MACT floor pursuant to Section 112, both its prior analysis and its proposed new analysis of the benefits of the CAMR will remain logically, factually and legally flawed.

The commenter stated that the NODA also fails to address the legal problems inherent in EPA's alternative Section 111 regulatory proposal. The commenter further stated that, instead, it focuses on a variety of technical issues that are at best a distraction from the central problems with the CAMR. According to the commenter, for example, the NODA contains an extensive discussion of comments EPA has received concerning the relationship between the CAMR and EPA's proposed Clean Air Interstate Rule (CAIR). See 69 Fed. Reg. at 69,868-69,871. But, according to the commenter, the EPA is required to develop lawful regulations pursuant to Section 112 of the Clean Air Act regardless of what its models, or any commenters' models, reveal about the consequences of CAIR. The commenter added that, equally important, EPA recently announced that it is delaying the implementation of the CAIR indefinitely. See Exhibit A (D. Samuelsohn, "Bush Holds CAIR Release As Congress Shows Interest in Clear Skies," Greenwire, Dec. 13, 2004) (also available at http://www.eenews.net/Greenwire/Backissues/121304/121304gw.htm). The commenter stated that, accordingly, EPA should not base either its Section 112 or Section 111 approach on estimates of what CAIR might or might not accomplish.

Response:

EPA issued the NODA to take further comment on commenter's analyses submitted to docket after proposal and their impact on final rulemaking analyses. EPA took comment on its regulatory approach in the NPR and SNPR.

1. In some analyses, EEI assumed a 2.5 percent annual improvement in variable operating costs for ACI. Is it appropriate for an economic forecast to assume an improvement in costs over time and if so, what level of improvement in costs should be assumed?

Comment:

One commenter (OAR-2002-0056-5464) believes that EPA's modeling effort was deficient in that it assumes that technology will not advance and that the costs will not decrease and that as other EPA regulatory efforts have demonstrated, advances in control technology for Hg are occurring at great speed and costs will likely continue to decline. Additionally, the model did not consider sufficient control options, including precombustion controls, fabric filters and improvements in the functioning of existing controls. These options would provide a range of reductions, which were not accounted for in the model.

The commenter's concerns about the deficiencies of some of the modeling in the NODA and the agency's own effort are among the reasons they believed EPA should have conducted additional modeling of more effective MACT scenarios, with thorough discussions with the stakeholders about realistic and up-to-date inputs and assumptions.

Response:

EPA has conducted modeling analysis for the final rule under section 111. EPA's IPM model, due to model run time constraints, has to limit the number of control retrofit options available. EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis.

Comment:

One commenter (OAR-2002-0056-5446) stated that, typically, it is reasonable to assume that the costs associated of with technology will fall as the technology becomes more widely deployed and operational experience is obtained. However, it is premature to assume that dedicated Hg control technology will follow this trend in the years immediately following its introduction. In this case, the introduction of new regulation is likely to dramatically increase demand for the dedicated controls and sorbents required and it is likely that in the initial period supply will be not adequate for this new level of demand. Scarcity value will result in a corresponding increase in price.

Given the time value of money these near term impacts may have a significant impact on the net present cost of the proposed regulations. If the EPA decides it needs to more accurately represent the evolution of cost with time it must also capture the impact of potentially dramatic changes in the balance of supply and demand and the corresponding price impacts for both control technologies and sorbents such as activated carbon. Absent a detailed assessment of supply and demand the EPA should not assume that prices decline.

Response:

EPA has included the examination of technology improvement in its analysis of the costs of the rulemaking. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis. Given that the first phase cap is set at 38 tons, the Hg co-benefit reductions expected under CAIR, EPA does not anticipate demand impacts for control technologies and sorbents. EPA's analysis of past programs, like the NOx SIP call, indicate the markets respond to the demand for materials. See Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA, October 2002, in docket.

Comment:

One commenter (OAR-2002-0056-5488) stated that in the NODA, EPA invites comment on results from several alternative analyses submitted in comments on its proposed Hg rule and additionally invites "updated information on issues that may be relevant to assessing the assumptions employed in our power sector modeling." As a preliminary matter, it should go without saying that regulatory analyses performed by stakeholders are no substitute for the exercise of independent judgment by EPA. While EPA should consider comments submitted by stakeholders, it is a bedrock principle of administrative law that the agency must independently exercise its expertise to establish the grounds for its decisions. The commenter addressed their comments primarily to EPA's analyses, rather than those of the outside groups that are called out

in the NODA.

EPA's power sector modeling is fundamentally flawed because it ignores recent advances in control technology that have already occurred and moreover assumes that no advances will occur over the time frame of the regulations. The modeling is also overly restrictive in the control options it allows.

In projecting control costs over the time frame of this proposal, EPA must incorporate benefits of technological advances in control cost projections, especially given the fact that Hg control technology is already advancing very rapidly. In fact, OMB guidelines require that cost estimates used in agency rulemakings reflect "credible changes in technology over time." As described above, major advances in control technology accompanied by dramatic reductions in control costs have been demonstrated over the past year, rendering obsolete some of the most critical assumptions in EPA's power sector modeling. EPA is fully aware of many of these advances. Consequently, EPA's assumption that control costs will not change over the next decade is clearly untenable. EPA must adjust the starting point for its control cost estimates to reflect current reality, and further must incorporate a reasonable rate of improvement in its forecasts. Because empirical estimates of the rate of improvement in control costs over time are sparse, EPA should begin with reasonable base case estimates of improvement rates and conduct sensitivity analyses to examine the importance of this parameter. Based on experience with similar control programs and the advances in Hg control technology that have already occurred, a default assumption of no improvement is clearly unreasonable.

Modeling performed for the Clean Air Task Force (CATF) and other environmental groups demonstrates that much more stringent MACT emissions standards can be cost-effectively achieved than those proposed by EPA, even utilizing EPA's misguided scheme of setting disparate standards by coal rank. Furthermore, even with a cursory assessment of benefits, the CATF analysis shows that the benefits of the more stringent standards they examined would outweigh the costs. EPA should take this comment into account in revising its own power sector modeling, by exploring alternative levels of stringency for the MACT standards. EPA must go beyond the CATF analysis, however, and consider stringent standards for all ranks of coal and coal blends, for new and existing units.

Response:

EPA has conducted modeling analysis for the final rule under section 111. EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis.

Comment:

One commenter (OAR-2002-0056-5502) stated that technological advances anticipated from specific on-going research programs could reduce the costs of the proposed Cap and Trade rule by up to 30 percent, but would provide no significant reduction in the costs of the alternative MACT approach.

Response:

EPA has conducted modeling analysis for the final rule under section 111. EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis.

Comment:

One commenter (OAR-2002-0056-5535) stated that EPA requested comment on whether the economic model should account for improvement in technology costs over time. The commenter believed that it should. The commenter noted in their comments on the proposed rule, the IPM assumes that control technologies are static, leading to an overestimate of control costs. In particular EPA should account for the expected decrease in the cost of activated carbon, as this expense comprises the bulk of variable operating costs. EPA has previously stated that the cost of activated carbon is expected to decrease by 40 percent with widespread implementation of the technology. In addition, the IPM should be adjusted to account for the lower quantity of halogentated carbons that would be needed and the lower quantity of solid waste generated. Also, because the brominated carbons do not affect the quality of fly ash for use in concrete, EPA must revise the assumptions in the IPM related to loss of revenue from flyash sales.

Response:

EPA has conducted modeling analysis for the final rule under section 111. EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of of a second ACI option using advanced sorbents. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis.

Comment:

One commenter (OAR-2002-0056-5497) stated that it was inappropriate for an economic forecast to assume a decrease in variable costs over the foreseeable future for Hg controls. With respect to ACI, activated carbon reagent now costs $0.50/lb and is unlikely to decrease to any significant degree. The business of manufacturing this reagent is already mature and this is not a situation where a product with a limited production volume and history is likely to experience decreases in unit cost. Indeed, activated carbon already has significant existing demand and the implementation of ACI at power plants is more likely to increase its unit cost. EPA estimated in 2002 that demand for both activated and granular carbon to be 227,000 tons in 2004, in comparison to a manufacturing capacity of 233,000 tons annually. EPA also estimated that about 70 GW of coal-fired capacity would retrofit ACI, requiring an additional 220,000 tons of activated carbon. Doubling the demand from already high production rates could well increase and not decrease the unit cost of activated carbon. For this reason, an assumption in EPA's model that activated carbon costs will remain the same over time may underestimate the actual costs.

Response:

EPA has conducted modeling analysis for the final rule under section 111. EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of advanced sorbents, leading to lower capital costs not variable operating costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis. With regard to demand for activated carbon, EPA notes that the report cited by the commenter indicates that markets respond to the demand for materials, much like under the NOx SIP call supply for catalyst increased with demand. See Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA, October 2002, in docket.

Comment:

One commenter (OAR-2002-0056-5469) noted that in its June 2004 submission (see OAR-2002-0056-2929), Charles River Associates provided results for a set of five different possible rates of technological change. These included a 2.5 percent and 4 percent p. a. rate of reduction in our base assumptions for variable O and M costs on the sorbent-based control technology (referred to generically as ACI here), and a 1 percent and 2 percent p. a. rate of reduction in our base assumptions for capital costs, and variable and fixed O&M. The first two cases were intended to reflect future reductions in the costs of sorbent and/or injection rates (lb/Macf) needed to achieve each level of percentage removal through an advanced sorbent technology. The second two cases reflected future reductions also in the cost of the baghouse technology that is assumed necessary in our base assumptions in order to achieve the lowest $/ton removed for percentage reductions in the 60-90 percent range (i.e., TOXECON ^{TM}). This could imply refinements in design or materials of the baghouse, or possible development of more cost-effective alternatives that would still entail initial costs, but for some less costly alternative to a COHPAC baghouse that still reduces the sorbent injection rates than are currently necessary to achieve high percentage reductions in front of an ESP only. Finally, a 0 percent rate of improvement was also considered.

The commenter suggested that these scenarios presented a range of possibilities for exploring how much the prospect of technological improvement might affect results. It is almost certain that some degree of cost reduction will occur if time is permitted, and that the likely reductions will be increasing with time. Charles River Associates did not suggest that anyone of these is a most likely case, but the range of prospects is quite broad, and it provides a good test bed for understanding the impacts of technical change on costs of a Hg cap-and-trade policy that provides for a gradual phase-in of control installations.

In its June submission (see OAR-2002-0056-2929), the commenter reported that the marginal costs of controls, especially in later years, were quite sensitive to any rate of improvement, and that estimated total costs of controls also fell. These are not surprising results, and the main interest was the degree to which allowance prices might be keep below levels such as that set by EPA's proposal as a "safety valve" price of $31,500 (1999$). With any but the worst case assumption of zero technological improvement, marginal costs of control were projected to remain below that price through 2020, even when emissions achieve the 15 ton

level. Table 8 reproduces the allowance price sensitivities that the commenter reported in the June submission.

Table 8. Projected Mercury Allowance Prices Under Alternative Assumptions of Rates of Improvement in Hg Control Technology
($/lb Hg, in 1999$; 2020 marks start of terminal period in model used)

Year	Annual Rate of Technological Improvement on Activated Carbon Infection Control Methods				
	0%	1.5%	2.5%	2.5%	4.0%
		Capital and O&M	Capital and O&M	Variable O&M only	Variable O&M only
2010	$22,108	$21,850	$22,345	$20,854	$20,090
2012	$21,654	$19,623	$17,904	$18,727	$17,420
2015	$25,826	$23,404	$21,353	$22,335	$20,775
2018	$30,824	$27,933	$25,485	$26,657	$24,796
2020	$37,285	$28,495	$23,611	$32,536	$30,951

The glide paths of all five of the cases considered in our June 2004 submission are not different enough to merit a graph. They all attained Hg emissions of 15 tons by 2020. A conclusion that the commenter can draw from this set of runs is that technological change is more likely to affect costs, and particularly marginal costs, of meeting a cap, but that it does not much alter the glide path between Phase I and Phase II of a policy.

Response:

EPA agrees with the commenter that Hg technology costs are likely to improve over time. EPA has conducted modeling analysis for the final rule under section 111. EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis.

2. The IPM has limited Hg control retrofit options. Currently, it assumes that Hg reductions are achieved only through SCR and FGD or ACI (with or without fabric filter). Should other control options be considered(e.g., retrofit of fabric filters and electrostatic precipitators, pre-combustion controls, and optimization of SO_2 or NO_x controls?

Comment:

One commenter (OAR-2002-0056-5464) states that one of their biggest concerns regarding the NODA is that it focuses undue attention on the IPM modeling that commenters submitted and their related inputs, assumptions, results and, particularly, the cost of control, control efficiency and the technical feasibility of various control options. The discussions about cost, especially, distract from the most important point of all: the Clean Air Act clearly calls for

emissions of hazardous air pollution from electric utilities to be regulated under Section 112, which requires EPA to establish a MACT standard that reflects at least "the average emission limitation achieved by the best performing 12 percent of the existing sources" or "the emission control that is achieved in practice by the best controlled similar source." Consideration of cost is inappropriate during the determination of the MACT floor and should be used only in calculations of MACT levels that are beyond the floor. Therefore, the cost calculations articulated in the NODA should not be part of the determination of the MACT floor for electric utilities.

To the extent that some of the modeling is useful in considering MACT options beyond the floor, however, the commenter offers some general observations about what is contained in the NODA.

The commenter does not believe the information contained in the NODA portrays the tremendous advancements in control technology that have come about recently, even since the proposal was issued. As up-to-date data show, controls that can result in significant, MACT-level reductions are not only technically feasible, but are also cost-effective and commercially available. These controls include low NO_x burners, activated carbon injection (ACI) with various sorbents, selective catalytic reduction, enhanced wet scrubbers, fabric filters and acid gas controls for reducing Hg emissions. These are already available for installation on coal- fired utility boilers for all types of coal.

Unfortunately, several of the modeling results summarized in the NODA do not account for recent technological developments (e.g., halogenated sorbents) or adequately consider control options (e.g., low NO_x burners or fabric filters) in their assumptions and calculations. As a result, their conclusions do not reflect what is currently possible and skew cost and emission reduction estimates.

The ACI-type of control, which is currently commercially available, has low capital cost and minimal maintenance requirements. There have been recent improvements in sorbents that result in significant cost reductions and increased control efficiency. ACI can reduce Hg emissions by over 90 percent, can be installed quickly and is effective on both bituminous and subbituminous coals.

Response:

EPA is finalizing a rule under Section 111 and has conducted modeling analysis for the final rule. EPA's IPM model, due to model run time constraints, has to limit the number of control retrofit options available. EPA agrees with the commenter that Hg technology costs are likely to improve over time. EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development whitepaper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5332) noted that EPA indicates in the NODA that "due to model size considerations, limited knowledge on achievable levels of Hg control, and limited know ledge on assessing the full impact of the Hg speciation profile on control," the IPM modeling it has performed assumes Hg reductions are achievable only through use of SCR and wet FGD, or ACI. The commenter understands that model size considerations impose limitations on the number of control options that can be analyzed. However, since at least some stakeholders are questioning whether ACI should be considered to be a commercially available technology prior to 2010 (see discussion below), limiting the modeling to these two control options may not provide a representative range of achievable Hg emissions reductions and control costs.

The commenter suggested that the model should include, at a minimum, retrofitting plants with fabric filters as an available control option. According to EPA's own analysis of its extensive ICR database, fabric filters are capable of achieving an average of 90 percent Hg removal on units burning bituminous coal and over 70 percent removal on units burning subbituminous coal. Moreover, no one would question the commercial availability of this technology.

A host of other options are still undergoing testing and only preliminary performance and cost data are available. These include: (1) optimization of existing SO_2 and $_{NOx}$ controls; (2) pre-combustion controls (e.g., fuel cleaning and fuel blending); (3) alternative sorbents (e.g., halogenated activated carbon, non-carbon based sorbents); (4) back-end additives and oxidation catalysts; and (5) multi-pollutant technologies. In light of the ongoing testing of these control options and considering model size limitations, the commenter supports the decision not to include these options in the modeling analyses.

Response:

EPA's IPM model, due to model run time constraints, has to limit the number of control retrofit options available. EPA agrees with the commenter that Hg technology costs are likely to improve over time. EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of second ACI option, using advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5484) stated that in the NODA, EPA asks for updated information on Hg control options such as activated carbon injection (with and without fabric filters), including the time line for commercialization, cost, balance of plant impacts, and performance. To that end, the commenter commissioned RMB Consulting and Research, Inc., to develop the report entitled, "The Potential Effect of Activated Carbon Injection on Coal-Fired

Power Plant Operation." This report details the operational difficulties associated with activated carbon injection, both with and without a fabric filter. It concludes that these balance-of-plant impacts will limit the applicability of activated carbon injection, especially into existing electrostatic precipitators and bag houses.

Response:

The Agency's position on the state of Hg technology, including ACI, is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5559) stated that EPA should consider adjusting the Hg control levels for several technologies in the IPM model to reflect optimal control. For example, fabric filters are effective at controlling all forms of Hg species. However, decreasing flue gas temperatures and increasing exhaust gas contact time with the filter cake can further enhance elemental Hg control. Therefore, the control levels assumed in the IPM model for fabric filters should be higher than the 72 percent and 90 percent average control levels determined by the 1999 ICR data respectively for sub bituminous and bituminous fired units.

The IPM control options need to be expanded to include dedicated and integrated Hg control technologies. At the minimum, a fabric filter operating at optimal Hg control levels should be an available option for new and existing utility units as a dedicated control technology. Integrated Hg control technologies that should be added include the addition of sorbent injection and oxidizing technologies in conjunction with new and existing control systems.

The IPM model should also be improved by inclusion of recently tested control options. One prime example is the development of brominated activated carbon by Sorbent Technologies. This sorbent has demonstrated very high Hg reductions at a cost lower than activated carbon regardless of Hg speciation or control system. This sorbent is also available in a form compatible with cement fly ash re-use. The availability of this sorbent and other injection materials with similar outcomes such as sodium tetrasulfide and ADVACATE multi-pollutant sorbent support inclusion into the IPM model. Similarly, EPA needs to incorporate advancements in oxidation catalysts and agents into the IPM model.

Response:

EPA's IPM model, due to model run time constraints, has to limit the number of control retrofit options available. The ACI option in EPA' s IPM includes the addition of a pulse-jet fabric filter to achieve 90% control. EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of second ACI option using advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric

Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5591) stated that injecting a sorbent such as powdered activated carbon, bromine, polysulfides, or other sorbent into the flue gas represents a relatively simple approach to controlling Hg emissions from coal-fired boilers. The gas-phase Hg in the flue gas contacts the sorbent and attaches to its surface. The sorbent with the Hg attached is then collected by the existing particle control device, either an electrostatic precipitator (ESP) or fabric filter (FF).

The air pollution control industry already has considerable experience with the implementation of Hg controls for other industrial sectors. Sorbent injection has been commercially proven to augment the removal of Hg in waste-to-energy plants. Experience controlling Hg emissions has been gained in more than 60 U.S. and 120 international waste-to-energy plants that burn municipal or industrial waste or sewage sludge. For the past two decades, sorbent injection upstream of a baghouse has been successfully used for removing Hg from flue gases from these facilities. Other reagents used include activated carbon, lignite coke, sulfur containing chemicals, or combinations of these compounds. The Hg control experience gained from the municipal and industrial waste combustors demonstrates that the air pollution control industry has been able to control Hg in the past and is able to apply their expertise to the electric power sector.

Powerspan Corporation's Electro-Catalytic Oxidation (ECO) is an integrated multipollutant control technology that achieves major reductions in emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), fine particulate matter ($PM_{2.5}$), and Hg. The technology also reduces emissions of other air toxic compounds and acid gases such as arsenic, lead, and hydrochloric acid (HCl). ECO produces a commercial fertilizer co-product, reducing operating costs and avoiding landfill disposal of waste.

ECO is situated downstream of a power plant's existing electrostatic precipitator (ESP) or fabric filter. The system consists of three gas-processing steps, including a barrier discharge reactor, an ammonia-based wet scrubber, and a wet ESP. The barrier discharge reactor oxidizes SO_2, NO_x, and Hg; the ammonia scrubber removes SO_2, NO_2, and oxidized Hg creating an ammonium sulfate nitrate solution; and the wet ESP captures acid aerosols, fine particulate matter, and oxidized Hg.

Liquid effluent produced by the scrubber contains dissolved ammonium sulfate nitrate (ASN) salts, along with Hg and captured particulate matter. The ASN solution is sent to a co-product recovery system, which includes filtration to remove ash and a sulfur impregnated activated carbon adsorption bed, which removes Hg from the effluent stream. The Hg and spent activated carbon are disposed of as hazardous waste. The treated co-product stream, free of Hg and ash, can be used directly in liquid form or processed to form ammonium sulfate nitrate fertilizer in crystalline or granular form.

KFx, Inc. has a patented and proven pre-combustion technology that transforms low-cost, low-grade western coal (e.g., lignite or subbituminous) into a clean, affordable, efficient energy

source, called K-Fuel. K-Fuel pre-combustion technology applies heat and pressure to boost the heat value of subbituminous coal and lignite by 30-55 percent, from approximately 8,000-8,800 Btu/lb to 11,00011,500 Btu/lb, optimizing combustion in a manner that produces more generation output per ton of coal while lowering emissions. Moisture in the coal can be reduced by as much as 80 percent from approximately 30 percent in the feedstock to seven percent in K-Fuel.

Similar to post combustion SO_2, NO_x, and PM controls, Hg emission reductions from the K-Fuel technology are a co-benefit of the pre-combustion process. K-Fuel provides a pre-combustion Hg removal solution, reducing Hg content by up to 70 percent or more. In addition to Hg reductions, K-Fuel also reduces emissions of SO_2 and NO_x.

Response:

EPA agrees with the commenter that there are likely many technology advances in the control of Hg. EPA has performed a sensitivity analysis assuming the introduction of second ACI option using advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5475) stated that it recommends modification of the IPM modeling with respect to using additional control options. Additional control options (e.g., retrofit of fabric filters and electrostatic precipitators, brominated activated carbon injection) should be considered in EPA's power sector modeling. This commenter believes that the current approach, which only takes into account selective catalytic reduction (SCR), flue gas desulfurization (FGD), and activated carbon injection (ACI), underestimates the benefits achieved by other technologies. Consideration of additional controls in the modeling would yield more realistic results.

Response:

EPA agrees with the commenter that there are likely many technology advances in the control of Hg. EPA has performed a sensitivity analysis assuming the introduction of second ACI option using advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis.

Comment:

One commenter (OAR-2002-0056-5446) stated that EPA should consider the addition of other control options such as fabric filters and ESP's where the performance of these technologies can be sufficiently well characterized for the purpose of a regulatory decision.

EPA should not model control options that have not been reasonably demonstrated at an

appropriate scale and over the range of operating conditions that a real plant will encounter. Short-term field tests or demonstration projects are an inadequate basis for regulatory decisions.

The EPA should not include pre-combustion removal technologies unless there has been adequate flue gas testing at sufficiently representative generating plants to ensure that performance can be adequately characterized. Given the uncertainties and complexities of Hg flue gas chemistry it is inappropriate to assume that reductions in coal Hg content achieved in small scale testing will reflect the reductions flue gas Hg content that may be achieved if and when potential pre-combustion technologies are commercialized.

The commenter said that it would be arbitrary and unreasonable to base an emissions standard on the hypothetical performance of unproven technology.

Response:

EPA has performed a sensitivity analysis assuming the introduction of second ACI option using advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5510) stated that absent a rational basis, EPA should not make assumptions about reduced capital and maintenance and operating costs for ACI. Alternatively, they believe that EPA should model a case where demand, coupled with supply constraints, dries up capital and operating costs, in particular for the activated carbon sorbent.

World consumption of activated carbon is expected to increase by 4 percent per year from its current level of 750,000 ton/year, effectively using up planned production capacity increases by 2005. Two-thirds of the planned capacity expansion is in China or Southeast Asia, while production facilities in the U.S. are being shut down. The availability and cost of activated carbon is significant because all of the modeling results EPA presents in the NODA assume the application of ACI to meet the 2010 compliance requirements, applied to 10 GW to 120 GW of generating capacity. At a 10 lb/MM SCF treat rate, this would require 60,000 to 700,000 lb/year of activated carbon. Therefore, there is the potential that demand for activated carbon in the U.S. could create supply shortages and corresponding price increases.

EPA should not model control options that have not been demonstrated on a commercial basis. As noted in our comments dated, June 29, 2004, this does not mean a control technology that a vendor is willing to sell, but a technology that performs in a predictable manner when used with boilers of various designs over the range of operating conditions that the plant will encounter. Short-term field tests or demonstration projects are not sufficient to conclude that a technology is commercially available. Modeling based on the hypothetical performance of unproven technologies will produce speculative results and cannot be used to determine the performance of the technology for specific units with a high degree of confidence. Such

information should not form the basis for regulatory decisions.

Response:

Given that the first phase cap is set at the Hg co-benefits of CAIR, EPA does not project significant amount of ACI to be retrofitted until the 2018 timeframe. With regard to demand for activated carbon, EPA notes that markets respond to the demand for materials, much like under the NOx SIP call supply for catalyst increased with demand. See Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA, October 2002, in docket. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5488) said that EPA should further modify its power sector modeling to treat control choices more realistically. EPA should configure the model to allow for retrofit applications/upgrades of fabric filters and to allow for pre-cleaning and coal blending as control options. EPA should also include halogenated sorbents as a highly cost-effective control option. Furthermore, EPA has assumed that sources must either control emissions at the 90 percent level with a fabric filter or at the 60 percent level using ACI alone. This discontinuous and unrealistic choice is likely to inflate estimated control costs and needs to be modified.

Response:

EPA's IPM model, due to model run time constraints, has to limit the number of control retrofit options available. The ACI option in EPA' s IPM includes the addition of a pulse-jet fabric filter to achieve 90% control. EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of second ACI option using advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis.

Comment:

One commenter (OAR-2002-0056-5535) stated that EPA has requested comment on whether other control options should be considered in EPA's power sector modeling (e.g., retrofit of fabric filters and electrostatic precipitators, pre-combustion controls, and the optimization of SO_2 or NO_x controls). The answer is yes. The commenter noted that EPA has had this information readily available since 2001 when EPA's Office of Research and Development published a report that described a number of retrofit options that could be undertaken to optimize the Hg capture of conventional controls. In addition, EPA had this information in hand in June 2002 when revisions to the IPM were being discussed with the Utility Working Group. These eleventh hour revisions to IPM clearly could have been made more than 2 years ago.

Response:

EPA's IPM model, due to model run time constraints, has to limit the number of control retrofit options available. The ACI option in EPA' s IPM includes the addition of a pulse-jet fabric filter to achieve 90% control. EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of second ACI option using advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis.

Comment:

The commenter (OAR-2002-0056-5455) wanted to fully reference the Forest County Potawatomi Community's (FCPC) excellent comment letter to EPA on the Hg utility rule (Document ID No. OAR-2002-0056-2173). The experts retained by the FCPC stated in attachments to that letter why EPA's proposed MACT standards were unacceptable and why EPA improperly failed to consider alternate methods of removal, such as activated carbon injection. We were unable to make specific comments on these issues as time was running short. The commenter also felt they could not add anything to the discussion that had not already been said in the FCPC letter. Comments made by Catherine O'Neill in her article "Mercury, Risk, and Justice" also captured the viewpoint of Fond de Lac Band.

Response:

As explained in the final rule preamble, EPA is finalizing mercury reduction requirements for coal-fired power plants under section 111. Also see the Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls and preambles to the rules.

Comment:

The commenter (OAR-2002-0056-5460) stated that EPA should consider other pollution control and pollution prevention measures in its power sector modeling. The commenter further stated that some of the measures EPA should be focused on are addressed in a recent report prepared by the National Wildlife Federation, a copy of which is attached as Exhibit E (See Document ID No. OAR-2002-0056-5460.).

Response:

EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of second ACI option using advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis.

Comment:

One commenter (OAR-2002-0056-5548) noted that EPA proposed adopting those coal rank allocation adjustment factors for the 2010 cap based on "equitable" grounds, with allocations adjusted by coal rank to "reflect the concern that installation of PM, NO_x and SO2 control equipment on different coal ranks results in different Hg removal." However, since EPA is relying upon other Hg-specific technologies to meet any subsequent cap beyond co-benefits, performance of PM, NO_x and SO_2 control technologies on coal ranks for any later cap would seem to be irrelevant. The relevant question is whether there is anything in EPA's projected availability of Hg-specific controls by at least 2014 that provides any equitable basis, supported by technical concerns, to award additional allowances to lower rank coals (and, thereby, take them away from bituminous coal).

Response:

As discussed in the Chapter 5, section 5.6.1, EPA is finalizing coal adjustment factors for the purpose of establishing state emission budgets of 1.0 for bituminous coals, 1.25 for subbituminous coals, and 3.0 for lignite coals. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Indian Country Emissions Budgets, EPA, March 2005.

Comment:

One commenter (OAR-2002-0056-5548) noted that, in the NODA, EPA asked for comment as to whether disparities in current NO_x and SO_2 Hg control capability among coal ranks justifies using different emissions trading allocation adjustment factors for each coal rank to reflect this disparity. In the commenter's opinion they did not. The point of co-benefits-based Hg emission reductions proposed by EPA is that the Hg reductions required to meet the proposed cap are made as a result of CAIR co-benefits, and no unit has to install controls specifically to reduce Hg. Hence, the specific ability of a unit (or the coal rank it is using) to make Hg reductions is largely irrelevant. Those that do need "reductions" to meet their allowance allocations get them through allowance purchases, and the ability of and cost to any particular unit to acquire allowances does not vary by coal rank. Notably, none of the units in the non-CAIR states, where a large portion of subbituminous coal is consumed, have to make any Hg reductions, and hence their ability to do so, regardless of coal rank, is irrelevant.

Response:

As discussed in the Chapter 5, section 5.6.1, EPA is finalizing coal adjustment factors for the purpose of establishing state emission budgets of 1.0 for bituminous coals, 1.25 for subbituminous coals, and 3.0 for lignite coals. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Indian Country Emissions Budgets, EPA, March 2005.

While the coal adjustment are used for determining the state budgets and are used in EPA's example unit allocation methodology, each State or Tribe is given discretion on how to distribute the allocations within a State or Tribe.

Comment:

One commenter (OAR-2002-0056-5548) stated that it is important to note that the required levels of industry-wide Hg reductions happen "automatically" as a result of co-benefits in aggregate. Consequently, in aggregate, there is no obligation for any unit to actually install any control equipment specifically to meet a Hg reduction requirement. EPA's proposal declares, and fundamentally rests upon, the principle that no unit should have to install any controls specifically to reduce Hg, as such controls are not plausibly cost effective. Because the level of co-benefits Hg reductions that will be achieved under the CAIR includes different reduction assumptions for each of the coal ranks, differences in actual Hg reductions among coal ranks have already been accounted for in setting the industry-wide co-benefits cap.

As a consequence of the co-benefits approach, neither EPA nor the commenters referenced in the NODA may rationally award differing amounts of allowances to the various coal ranks based on the notion that members of any coal rank will have to install controls to reduce Hg. To do so would be to declare such Hg-only controls technically and economically unjustified as the best system of reductions under section 111 on the one hand, but to act as if such controls were required when allocating allowances, on the other. Hence, relative abilities among coal rank to control Hg under the CAIR or otherwise are generally irrelevant.

While Hg control disparities among coal ranks and associated equities are not relevant in aggregate under EPA's co-benefits approach, they may seem to be relevant at the individual unit level, and therefore further analysis is required. The co-benefits approach creates two general classes of utility units: those that will install co-benefits technology and those that will not. More specifically, for compliance purposes, two classes of utility units are created: those that buy allowances to comply, and those that are selling allowances based on their co-benefits reductions.

Response:

As discussed in the Chapter 5, section 5.6.1, EPA is finalizing coal adjustment factors for the purpose of establishing state emission budgets of 1.0 for bituminous coals, 1.25 for subbituminous coals, and 3.0 for lignite coals. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Indian Country Emissions Budgets, EPA, March 2005.

Comment:

One commenter (OAR-2002-0056-5497) stated that the use of ACI with an electrostatic precipitator (ESP) has inherent uncertainties that may require the retrofit of additional collecting surface area for the ESP. The retrofit of an additional field may be required to enable the existing ESP to maintain particulate matter control efficiency. Given the uncertainties, many ESPs may have to be rebuilt with an increase in collecting surface area, to provide Hg control and retain control of particulate matter emissions. The commenter has provided assumptions that would allow ESPs that need additional plate area to accommodate ACI and have assigned a $25/kW capital charge for adding the extra field. However, that retrofit of an additional field may not be feasible in all instances, and the $25/kW capital charge for adding the extra field is

based on situations conducive to such additions.

The commenter rejected the suggestion that fabric filters can be widely retrofit to control particulate matter and significantly enhance Hg removal. Fabric filters are not feasible where flue gas SO_3 concentrations exceed about 5 ppm. It is possible that an engineering solution to the effects of high SO_3 concentrations on fabric filters may eventually be commercially available. Indeed, a panel session at the 2004 Mega-Symposium discussed possible solutions to such problems, but none are anywhere near proven at this time. Also, fabric filters are not practical for service in water-saturated flue gas conditions such as experienced downstream from wet scrubbers, since the water entrained in the flue gas will mix with the ash entrained on the filter, sealing off gas flow and fouling the filter surface.

Response:

As explained in the final rule preamble, EPA is finalizing mercury reduction requirements for coal-fired power plants under section 111, as such EPA is not mandating a specific control technology for compliance. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5469) noted that the NODA had requested further comment on the prospects of technological change in Hg control technology, on how it can be reflected appropriately in models, and on how it might affect policy choices. In response, the commenter has extended their analyses of technological change to attempt to reflect future availability of new control methods that have just recently begun to be tested and show promise of being cost-effective, especially for western coals or power plants equipped with hot-side ESPs. Significant questions remain about this new method's ultimate cost, control effectiveness, applicability to different types of units, balance-of-plant issues, and timing of commercial availability. However, once analyzed its potential impact on a "what if" basis using a range of assumptions related to these questions.

EPRI researchers provided information on "chemically-treated carbons" (CTC), a specific emerging advancement in sorbent technologies that would reduce the variable and capital costs of Hg controls. It is believed that these sorbents could become available for installations as early as 2010, and would allow the injection rate of the sorbent to be dramatically reduced for a given percentage removal, reaching 80 percent or more at subbituminous and lignite units without the use of a fabric filter or COHPAC.

The commenter has used the EPMM model to explore the impact of the CTC option becoming available at a future date (ranging from 2010 to 2012) under both the cap-and-trade policy and the MACT policy. It was assumed that any controls undertaken prior to that date would have to rely on the more costly conventional activated carbons with which the industry has greater experience to date. In order to achieve removals that can be as high as 90 percent on lower rank coals, sorbent injection with conventional sorbents requires the large capital

investment in a COHPAC (unless a unit already has a fabric filter). Even with bituminous coal, the cost-effective means of achieving 90 percent removal with present technology also entails the COHPAC investment because the sorbent injection rate would be very high without the COHPAC than with it (*e.g.*, about 20 lb/Macf without it, compared to about 2.5 lb/Macf with it).

There is still much uncertainty on the cost and effectiveness of all sorbent injection technologies, but especially the newer CTC option. Using information provided by EPRI researchers, "optimistic" and "pessimistic" CTC cases were prepared. The "optimistic" case assumed that CTC would not affect a company's ability to continue to sell its fly ash for use in concrete manufacture and other current commercial uses; that the CTC technology will be available in time for those plants that choose it as their preferred Hg control method to meet a compliance date of 2010; and that it would be made to work for bituminous units as well. The "pessimistic" case assumed that if CTC were used, the unit's fly ash would no longer be viable for concrete use; that it would be available in 2010, but at an operating cost that would be three times more expensive than it would become by 2012; and that it would not provide cost-effective options for bituminous units.

The effects of adding the CTC technology assumptions to the base EPMM scenario reflecting the Hg cap-and-trade policy were:

- The total number of Hg control retrofits is not much changed, but the fraction of retrofitted capacity that uses the CTC technology ranges from 27 percent to 64 percent.

- There is no significant effect on the emission glide path. Emissions in 2020 fall to 15.5 tons, compared to 15.4 in the standard case.

- Marginal costs of Hg control are reduced slightly compared to the case that does not have CTC, such that they are generally in the range of $20,000 to $30,000/lb (1999$) through 2020.

- Costs of the proposed Hg cap-and-trade scenario fall by 5 to 30 percent (in the pessimistic and optimistic cases, respectively) relative to the same modeled scenario that does not contain CTC technology.

In contrast, the effects of the CTC assumptions <u>on the MACT policy</u> were very minor:

1. The total number of Hg control retrofits required by 2008 continues to be very high, with over 67 GW of FGDs and over 64 GW of ACI-based controls required by 2008.

2. Only about 10 percent of capacity uses the CTC technology to meet the MACT. Those 10 percent do this by moth-balling during 2010-2011. The avoided capital costs of COHPAC offset their lost revenues, making waiting their preferred option.

3. Emissions in 2008 remain at about 32 tons, and fall to about 30 tons by 2020, as in our original MACT case.

4. Costs of the proposed MACT scenario are effectively unchanged from the case without

the CTC technology: $9.9 billion (1999$) compared to the original cost estimate of $10.1 billion (1999$).

These model results demonstrate what simple common sense is: if a MACT policy is implemented very soon, while relevant technologies are still in the early phases of innovation, it will be unable to benefit from technological improvement. These analyses do add some further value, however:

1. They provide an example of the impact of technological improvement on Hg control performance and costs through the case study of a specific technology.

2. They place a quantitative range on the potential cost reduction that this line of research might provide under a flexible, phased-in Hg policy.

3. They make it clear that the main beneficiaries of this potential innovation in Hg control technology under a MACT will be the marginal coal units that have small revenue prospects to start with, whereas a large portion of the universe of coal units can benefit from such an innovation under the more flexibly-timed cap-and-trade approach.

Based on these data, the commenter believed that technological advance in the specific form of chemically-treated carbon sorbents could reduce the estimated costs of the proposed cap-and-trade policy to a significant degree, but it would provide no significant reduction in the costs of the alternative MACT approach. In all, the main message regarding technological change is that its benefits are largely lost in a MACT setting, or in a setting that requires controls to be installed very rapidly. When a policy is designed to allow flexibility to adjust timing of controls, and to create sustained incentives to continue to reduce costs by pricing every unit of emissions, then costs of control may be moderated.

Response:

As explained in the final rule preamble, EPA is finalizing mercury reduction requirements for coal-fired power plants under section 111. EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of second ACI option using advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis.

3. To the extent that additional control considerations should be included, EPA is seeking data on the time line for commercialization, cost, balance of plant issues, and performance of such options.

Comment:

One commenter (OAR-2002-0056-5484) noted that over the past several months, pollution control equipment vendors have made many public pronouncements regarding the effectiveness of their equipment for Hg control. Unfortunately, when those same vendors are asked to guarantee Hg removal efficiency in contracts that they sign with their utility customers,

the control levels that they are willing to guarantee are much less than the optimistic claims they have made in public forums. For example, the commenter has signed an agreement with a major vendor to supply an SO_2 scrubber, which will also capture some of the Hg emissions. The differences between the public statements of this supplier and the actual contract language are described in Attachment 2 in of Docket ID No. OAR-2002-0056-5484.

Response:

The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5484) noted that EPA's proposed Clean Air Mercury Rule would require continuous monitoring of Hg emissions from electric utility steam generating units, either through the installation of Continuous Emissions Monitoring systems (CEMs) or through another appropriate method, such as proposed Method 324, Determination of Vapor Phase Flue Gas Mercury Emissions From Stationary Sources Using Dry Sorbent Trap Sampling. However, EPA's March 16, 2004, supplemental proposal states that Method 324 would only be available under certain limited circumstances, such as only for low-emitting units, or if quarterly relative accuracy test audits (RATAs) are performed. The commenter is concerned that such limitations will unnecessarily limit the applicability of Method 324, and, therefore, commissioned RMB Consulting and Research to develop the attached report, "Review of an Alternative Method for Continuous Mercury Emission Measurement: Method 324–Determination of Vapor Phase Flue Gas Mercury Emissions from Stationary Source Using Dry Sorbent Trap Sampling." This report concludes that Method 324, also known as the EPRI Quick SEMTM method, provides results comparable to both Hg CEMs and to the Ontario Hydro reference method.

The EPA has expressed concern that in order to administer a cap and trade program, realtime Hg emissions information is necessary and, therefore, CEMs will be necessary. However, the commenter wishes to emphasize that Quick SEMTM does provide continuous sampling and laboratories are developing analytical methodologies that will allow sample results to be available in hours, instead of the days that were previously required. Therefore, Quick SEMTM results will be available in time to provide information necessary for administration of a cap and trade program. The commenter urges EPA to promulgate Method 324 without restrictions on its use.

Response:

EPA agrees with the commenter. In light of comparative field data, EPA believes that monitoring using sorbent media should be as similar as possible to monitoring using Hg CEMS and therefore Section 75.81(a) of the final rule allows the use of sorbent trap systems for any affected unit, provided that rigorous, technology-specific QA procedures are implemented. The operational and QA/QC procedures for sorbent trap systems are found in section 75.15 and in appendices B and K of the final rule.

Recent field test data from several different test sites indicate that sorbent trap systems can be as accurate as Hg CEMS. However, EPA notes that although the restrictions on the use of sorbent traps have been removed, there are some inherent risks associated with the use of this technology. For instance, because sorbent traps may contain several days of accumulated Hg mass, the potential exists for long missing data periods, if the traps should be broken, compromised, or lost during transit or relative accuracy test audit (RATA) of a sorbent trap system is performed, the results of the test cannot be known until the contents of the traps have been analyzed. If the results of the analysis are unsatisfactory, the RATA may have to be repeated. This also may resulting in a long missing data period. However, EPA believes that these undesirable outcomes can be minimized by following the proper handling, chain of custody, and laboratory certification procedures in the final rule. The use of redundant backup monitoring systems can also help to reduce the amount of missing data substitution.

Comment:

One commenter (OAR-2002-0056-5556) noted that the EPA appropriately cites the Detroit Edison, St. Clair, Michigan pilot study on page 69870 in the Federal Register. This study is important in that it documents the successful application of the brominated powdered activated carbon (B-PACTM) process at the existing DTE Energy's Detroit Edison St. Clair Power Plant in August 2004. This preliminary 30-day pilot study conducted as part of the U.S. Department of Energy's National Energy Technology Laboratory's "Advanced Utility Mercury-Sorbent Field-Testing Program" demonstrated a 94 percent Hg control with B-PACTM injected into a cold-side electrostatic precipitator. This commenter noted that this study also demonstrated an 85 percent cost reduction from the current technology cost baseline (Nelson, S. 2004 and McCoy, M., et. al., 2004), and believes the final study should be factored into the EPA's analysis and regulatory decision.

Response:

EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of second ACI option using advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis.

Comment:

One commenter (OAR-2002-0056-5556) noted that in the NODA, the EPA states that the Integrated Planning Model utilized "finds the least-cost solution to meeting electricity demand subject to environmental, transmission, reserve margin, and other system operating constraints for any specified region and time period." Since the goal of the MACT standard is not to find a "least-cost" solution but rather a "best technology" solution, a model based on "least-cost" is not appropriate. Whatever modeling approach the EPA utilizes in its final analysis should be technology-driven and used to set a true MACT floor under Section 112 of the CAA.

Response:

EPA uses IPM to analyze the projected impact of environmental policies on the electric

power sector in the 48 contiguous States and the District of Columbia. IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. EPA used IPM to project both the national level and the unit level of utility unit Hg emissions under different control scenarios. EPA also used IPM to project the costs of those controls. As explained in the final rule preamble, EPA is finalizing mercury reduction requirements for coal-fired power plants under section 111.

Comment:

One commenter (OAR-2002-0056-5591) stated that EPA has requested comment concerning the availability of sorbent injection technologies to serve the electric power market. Activated carbon injection equipment is currently being sold to utilities. ACI equipment is identical for all coal types including bituminous, subbituminous, lignites and blends. Therefore, ACI equipment can be purchased for all coals and all plant configurations.

The specific sorbents may vary for different coals and operating conditions. In addition, the ability to accurately predict the levels of Hg removal that will be achieved will vary for different coals depending on the available performance data. For example, there have been a significant number of tests over the past year and a half on PRB coals and North Dakota lignites. Therefore, it is possible to estimate results for these configurations. There is less data on bituminous coals, so predictions will be less precise. Several full-scale field tests will be conducted on bituminous coals during 2005 and 2006. The first test on a Texas lignite will be conducted in 2005. Until this occurs, it is difficult to predict performance on Texas lignite.

The performance of activated carbon injection systems for lignite, subbituminous, and bituminous coals on various coal-fired power plant configurations are given in Table 1. The Hg reduction performance for these power plant scenarios are based on results from full-scale demonstrations that have been documented in various technical papers presented at major electric power conferences.

Table 1. Activated Carbon Injection Control Technology Options

Plant Configuration	Technology	Coal Type	% Reduction				Cost[c]		Year Commercially Available
			Min	Max	Avg. Total[a]	Avg. Incrm.[b]	Capital ($/kW)	O&M ($/kWh)	
CESP[d]	ACJ[f,g]	Bit	50	90	70	70	1.5 to 3	.0012	2004
	ACI[g,h]	Sub	0	95	80	80	1.5 to 3	.0005	2004
	ACI[i]	Lig	0	80	63	63	1.5 to 3	.0005	2004
CESP/FGD	ACI[j]	Bit	50	90	70	70	1.5 to 3	.0012	2004
	ACI	Sub	0	95	80	80	1.5 to 3	.0005	2004
	ACI[k]	Lig	0	80	60	70	1.5 to 3	.0005	2004

Plant Configuration	Technology	Coal Type	% Reduction			Avg. Increm.[b]	Cost[c]		Year Commercially Available
			Min	Max	Avg. Total[a]		Capital ($/kW)	O&M ($/kWh)	
CESP/FGD-dry	ACI	Bit	80	>90	>90	88	1.5 to 3	.00012	2004
	ACI	Sub	0	90	80	85	1.5 to 3	.00017	2004
	ACI	Lig	0	90	70	70	1.5 to 3	.00017	2004
CESP/SCR/FGD	ACI	Bit	50	90	70	70	1.5 to 3	.0012	2004
	ACI	Sub	0	95	80	80	1.5 to 3	.0005	2004
	ACI	Lig	0	80	60	60	1.5 to 3	.0005	2004
FF	ACJ[l]	Bit	20	95	85	80	1.5 to 3	.00036	2004
	ACJ[l,m]	Sub	20	90	90	80	1.5 to 3	.00054	2004
	ACI	Lig	20	80	80	75	1.5 to 3	.00054	2004
FF/FGD	ACI	Bit	50	95	90	70	1.5 to 3	.00012	2004
	ACJ[l]	Sub	30	90	90	80	1.5 to 3	.00027	2004
	ACI	Lig	30	90	85	70	1.5 to 3	.00027	2004
FF/SCR/FGD-dry	ACI	Bit	80	>90	>90	50	1.5 to 3	.00012	2004
	ACI[n]	Sub	0	>90	>90	90	1.5 to 3	.00017	2004
	ACI[o]	Lig	0	90	75	70	1.5 to 3	.00017	2004
FF/SCR/FGD	ACI	Bit	50	95	90	70	1.5 to 3	.00012	2004
	ACI	Sub	30	90	90	80	1.5 to 3	.00027	2004
	ACI	Lig	30	80	80	70	1.5 to 3	.00027	2004
HESP[e]	TOXECON[p]	Bit	20	95	85	80	3 + 15 to 3+ 50	.00036	2004
	TOXECON	Sub	20	90	90	80	3 + 15 to 3+ 50	.00036	2004
	TOXECON	Lig	20	80	80	70	3 + 15 to 3+ 50	.00054	2004
HESP/FGD	TOXECON	Bit	50	95	90	70	3 + 15 to 3+ 50	.00012	2004
	TOXECON	Sub	30	90	90	80	3 + 15 to 3+ 50	.00036	2004
	TOXECON	Lig	30	80	80	70	3 + 15 to 3+ 50	.00027	2004

Plant Configuration	Technology	Coal Type	% Reduction				Cost[c]		Year Commercially Available
			Min	Max	Avg. Total[a]	Avg. Incrm.[b]	Capital ($/kW)	O&M ($/kWh)	
HESP/FGD-dry	TOXECON	Bit	80	>90	>90	50	3 + 15 to 3+ 50	.00012	2004
	TOXECON	Sub	0	>90	>90	90	3 + 15 to 3+ 50	.00017	2004
	TOXECON	Lig	0	90	88	70	3 + 15 to 3+ 50	.00017	2004
HESP/SCR/FGD	TOXECON	Bit	50	95	90	70	3 + 15 to 3+ 50	.00012	2004
	TOXECON	Sub	30	90	90	80	3 + 15 to 3+ 50	.00036	2004
	TOXECON	Lig	30	80	80	70	3 + 15 to 3+ 50	.00027	2004

[a] This is the percent reduction attributable to the existing pollution controls and the technology.

[b] This is the percent reduction attributable only to the technology.

[c] In EPA's modeling, is it appropriate for an economic forecast to assume an improvement in costs over time (such as through technology cost reductions or through future technology innovation).

[d] CESP - represents cold-side electrostatic precipitator

[e] HESP - represents hot-side electrostatic precipitator

[f] Durham, M., J. Bustard, T. Starns, C. Martin, R. Schlager, C. Lindsey, K. Baldrey, and R. Monso (2004). *"Full-Scale Evaluations of Sorbent Injection for Mercury Control on Power Plants Burning Bituminous and Subbituminous Coals."* Power-Gen 2002, Orlando, FL, December 10-12.

[g] Nelson, S. Jr., R. Landreth, Q. Zhou, J. Miller (2004). *"Accumulated Power-Plant Mercury Removal Experience with Brominated PAC Injection."* Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, August 30 - September 2.

[h] Starns, T. Sjostrom, S., J. Bustard, M. Durham et al (2004). *"Full-Scale Evaluation of Mercury Control by Injecting Activated Carbon Upstream of a Spray Dryer and Fabric Filter."* Presented at PowerGen 2004, Orlando, FL, November 30 -December 4.

[I] Thompson, J.D., J. Pavlish, and M. Holmes (2004). *"Enhancing Carbon Reactivity for Mercury Control: Field Test Results from Leland Olds."* Combined Power Plant Air Pollutant Control Mega Symposium, Washington, D.C., August 29 - September 2.

[j] Dombrowski, K., et. al., (2004). *"Sorbent Injection for Mercury Control Upstream of Small-SCA ESPs."* Combined Power Plant Air Pollutant Control Mega Symposium, Washington, D.C., August 29-September 2.

[k] Starns, T, J. Amrhein, C. Martin, S. Sjostom, C. Bullinger, D. Stockdill, M. Strohfus, R. Chang, (2004). *''Full-Scale Evaluation of TOXECONIFM on a Lignite-Fired Boiler."* Presentation at the Combined Power Plant Air Pollutant Control Mega Symposium, Washington, D.C., August 29September 2.

[l] Ley. T., T. Ebner, K. Fisher, R. Slye, R. Patton, R. Chang, (2004). *"Assessment of Low-Cost Novel Sorbents for Coal-Fired Power Plant Mercury Control."* Combined Power Plant Air Pollutant Control Mega Symposium, Washington, D.C., August 29-September 2.

[m] Haythornthwaite, S., S. Sjostrom, et. al., (1997). *"Demonstration of Dry Carbon-Based Sorbent Injection for Mercury Control in Utility ESPs and Baghouses."* EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, Washington, D.C., August 25-29.

[n] Sjostrom, S., et. al., (2004). *"Full-Scale Evaluation of Mercury Control by Injecting Activated Carbon Upstream of a Spray Dryer and Fabric Filter."* Combined Power Plant Air Pollutant Control Mega Symposium, Washington, D.C., August 29 - September 2.

[o] Machalek, T., et. al., (2004). *"Full-Scale Activated Carbon Injection for Mercury Control in Flue Gas Derived from North Dakota Lignite*." Combined Power Plant Air Pollutant Control Mega Symposium, Washington, D.C., August 29-September 2.

[p] Berry, M, J. Bustard., et. al., (2004). *"Field Test Program for Long-Term Operation of a COHPAC@ System for Removing Mercury from Coal-Fired Flue Gas."* Combined Power Plant Air Pollutant Control Mega Symposium, Washington, D.C., August 29-September 2.

The commenter said that companies are providing firm price proposals with performance guarantees for every coal and boiler type. Activated carbon injection equipment is currently being sold to utilities. ACI equipment is identical for all coal types including bituminous, subbituminous, lignites and blends. Therefore, ACI equipment can be purchased for all coals.

The material resources, labor and time required to install the control equipment is an additional topic to consider. With regards to the items that impact APC vendors, there are sufficient fabrication/manufacturing resources in the U.S. market to support a rapid retrofit of the industry with sorbent injection systems in addition to the systems required for the Clean Air Interstate Rule. These systems are relatively simple compared to FGD and SCR systems and the major components are commonly used in a variety of industrial processes from numerous manufacturers throughout the U.S.

As mentioned in the commenter's previous comments on EPA's proposed Hg rule, there is significant excess production capacity of powder activated carbon and a strong interest in investing significant capital in building new production facilities exists among current suppliers (both in the U.S. and in China). A new Hg regulation would create a significant new market for activated carbon. In order to build new production capacity, between a two- to four-year period would be needed to expand production. However, all of the activated carbon suppliers said that they would be hesitant to invest capital resources to increase capacity based only on the promise of a new regulation. A decade or so ago, the AC industry increased capacity when EPA announced that they were going to tighten up drinking water standards. After the new capacity was added, EPA did not follow up with new regulations, which produced a glut of activated carbon. Some companies went out of business because of this, and the industry as a whole is just now recovering. As a result, it is unlikely that new AC production will move beyond the planning stages until there is the certainty of a regulation.

Concerning resources for fabric filter systems, should the market dictate the need for secondary PM control (not all applications will require this) there will be sufficient engineering and material resources to complete the necessary projects. There are several examples where the industry has had to retrofit a significant number of boilers with APC controls to meet new

environmental regulations. Examples include the retrofit of ESPs in the 1970s and the more recent retrofit of almost 100 GW of SCRs for the NO_x SIP Call. These examples support the assertion that, should the utility industry need to retrofit a large number of coal-fired boilers with Hg controls, it can be accomplished in a short period of time. The industries that support this market (APC suppliers, fabricators, construction firms, etc.) have repeatedly demonstrated their ability to meet rapidly increasing market demand. In addition, increasing demand for systems and fabrication can also be met by foreign suppliers of silos, fabric filter systems, fabrication and supply of PAC.

If there is a bottleneck in retrofitting the U.S. fleet of coal-fired boilers, it is not likely to be in the area of the supply of capital equipment or under supply of sorbents but more likely to be impacted by issues that are within the scope of the utility or regulatory community itself. Examples include areas such as project permitting/PUC approval, availability of project financing, and unit outage scheduling. These are all items that are out of the control of APC vendors but may impact the timing for control installation.

The commenter noted that EPA reported that the Edison Electric Institute (EEI) estimated that ACI would be less expensive per pound of Hg removed than EPA has estimated. Meanwhile, other power industry models assumed higher capital costs for ACI than EPA in its modeled scenarios. EPA is seeking comment on whether its assumptions for Hg control technology costs are reasonable.

EPA raised several questions in the NODA requesting information on sorbent injection technologies and how best to make modeling assumptions to reflect current and future capabilities of Hg control technologies. One of the questions raised by EPA was concerning the use of discounted variable operating costs for activated carbon injection (ACI). EPA questioned whether it would be appropriate for an economic forecast to assume an improvement in costs over time (such as through technology cost reductions or through future technology innovation), and what level of improvement in costs to assume. Specifically, EPA questioned whether a 2.5 percent annual improvement in variable operating costs for ACI should be incorporated into their modeling as has been done for similar power sector models.

In regards to decreasing costs, it is appropriate to assume that the cost of sorbent technologies will decrease with time due to equipment/technology innovation, improvements in sorbent removal efficiencies, and the reduction in sorbent production costs. The primary cost of sorbent injection technology is due to sorbent usage so the largest cost reductions are likely to be made with the sorbent costs. The capital costs for ACI are relatively low as the equipment is mechanically simple compared to FGD and SCR systems for coal-fired power plants. Activated carbon injection systems consist of a bulk-storage silo; blower/feeder system to convey the activated carbon from the silo through hard piping leading to the flue gas duct; and injection probes located in the flue gas duct. Currently, the annual operating costs for these systems will be more than the cost to construct the system.

Costs are expected to decrease as sorbents are developed specifically for the coal-fired boiler application. It is widely known that the current sorbents have much higher capacity for Hg removal than can effectively be used in a coal-fired power plant application. This is because the injected sorbent will be rapped off the plates of the electrostatic precipitator or cleaned off

the bags of the fabric filter before the absorption/adsorption capacity of the sorbent has been fully utilized. Therefore, work is being done to produce a lower capacity, lower cost sorbent that will be more appropriate for use in this industry.

It is also expected that technical innovations will lead to lower cost sorbents. For example, ADA-ES has reported improved Hg removals on full-scale tests with NORIT's new activated carbon named E-3. These tests showed that significantly higher levels of Hg could be removed at significantly lower feed rates than earlier tests indicated. With this kind of technology improvement, the overall cost for Hg removal will decrease over this. This is especially true for Western coals (i.e., lignite and subbituminous) as sorbent injection rates are expected to be higher for those units yielding a drop in operating costs by a factor of two to four. It is expected that similar improvements in sorbents will result in similar cost reductions for bituminous coals.

As far as production costs are concerned, there will likely be a reduction in cost to produce sorbent products for the power industry due to economies of scale. Currently, activated carbon is already manufactured by numerous vendors for a wide variety of customized applications requiring inefficient and expensive materials handling to provide the different treatments and particle size requirements. In addition, the demand for activated carbon is seasonal and therefore the use of the equipment is not optimized. To meet the power industry demands, it is likely that new production facilities will be built to produce only a few products so there will be an increase in efficiency and reduction in cost. In addition, the power market will be much more consistent and predictable, which will serve to optimize the production equipment.

Once the sorbents are specifically produced for power industry applications, the pricing trend for activated carbon should act very much like other commodities. On average, pricing for most commodity items will normally stay unchanged or decrease slightly over time as market forces encourage cost reductions. Since inflation in the U.S. normally runs around 2-3 percent, any commodity that does not increase in price decreases (in real terms) by around this amount every year. It is safe to assume that activated carbon prices will decrease by at least 2-3 percent in real terms (net inflation). The most likely scenario is that prices for sorbents will initially decrease by much more than 2-3 percent as the market for this specific application grows and will reach a steady state annual reduction of 2-3 percent.

The final decrease in costs will come about through innovative equipment/technology configurations such as the EPRI TOXECON II. Currently, EPA modeling includes the cost for the loss of sale of power plant fly ash plus landfill costs to dispose of the fly ash. The EPRI TOXECON II process eliminates the cost of loss of sale of the fly ash for concrete without the need for a new fabric filter. As a result, plants will be able to avoid one of the most costly aspects of the technology. As shown in Table 1, the capital cost of installing a COHPAC fabric filter is expected to range between $15 - 50/kW depending on the plant configuration. Also given in Table 1, the capital cost of installation ACI systems is expected to range between $1.5-3/kW.

When considering the combination of the decrease in cost of sorbent technologies with time due to equipment/technology innovation, improvements in sorbent removal efficiencies,

and the reduction in sorbent production costs; it is safe to assume that costs for this technology will decrease over time. A more likely scenario for costs of ACI over the next three to five years would be more significant reductions in overall costs by a factor of 2 or more compared to current EPA and DOE projections of only 2.5 percent.

The ECO process is currently being commercially demonstrated in a 50-MW slipstream unit at First Energy Corporation's R.E. Burger Plant in Shadyside, Ohio. The unit processes flue gas from a plant burning eastern bituminous coal. As of August 2004, ECO performance has met or exceeded most commercial objectives. Mercury removal across the ECO system has ranged from 75-85 percent with total inlet Hg concentration up to 16 $\mu g/Nm^3$. SO_2 removal is routinely greater than 99 percent with inlet SO_2 concentrations up to 2200 ppm and outlet concentrations below 10 ppm. NO_x removal has been as high as 82 percent with outlet levels of 0.05 lb/MMBtu.

Prior to proceeding with the 50-MW commercial demonstration unit, Powerspan conducted pilot testing in a I-MW slipstream unit at the R.E. Burger Plant. During approximately 18 months of testing, the plant burned a blend of bituminous and subbituminous coals. Typical values for Hg concentration, chlorine, and sulfur content in the coal were 0.09 ppm Hg, 0.06 percent chlorine, and 1.9 percent sulfur. Ontario-Hydro sampling was conducted by Air Compliance Testing (Cleveland, Ohio) at the ECO pilot unit in May 2002. Ontario Hydro testing measures gas-phase Hg (elemental and oxidized forms) and Hg bound to particulate matter in the flue gas. Air Compliance's testing consisted of three sample runs each on the inlet and outlet flue gas streams. Two of the three sets of sample runs had sample durations in each location of four hours while sampling for the remaining set of runs lasted three hours in each location. The Hg removal for particulate, oxidized, and elemental are provided in Table 2 with the overall Hg removal measured at 88 percent.

Table 2. Mercury Removal at ECO Pilot Demonstration

Hg Fraction	ECO Inlet	ECO Outlet	% Removal
Particle Bound Hg (µg/dscm)	0.62	0.016	97.4
Oxidized Hg (µg/dscm)	5.81	0.022	99.6
Elemental Hg (µg/dscm)	0.16	0.75	
Total Hg (µg/dscm)	6.59	0.79	88.0

Table 2 provides estimates of the ECO process performance for various plant configurations. It is expected that 80 percent Hg removal across the ECO system will be achieved with the application of the ECO process for units burning bituminous coals. The average incremental removal for fabric filter and hot-side ESP applications are expected to be similar to that demonstrated at the ECO commercial demonstration unit at the R.E. Burger Plant, which employs a cold-side ESP. The cost and performance estimates are based on results currently being commercially demonstrated in a 50-MW slipstream unit at First Energy Corp.'s R.E. Burger Plant.

Table 2. Mercury Removal Capacity of ECO Commercial Technology

Plant Config-uration	Coal Type	% Reduction				Cost			Year Commerc-ially Available
		Min	Max	Avg. Total[a]	Avg. Increm.[b]	Capital ($/kW)	O&M ($/kW h)	% Expected Change Cost ±w/ time[c]	
CESP[d]	Bit	[f]	[f]	[f]	80	225	0.0027	Decrease	2006
FF	Bit				80	225	0.0027	Decease	2006
HESP[e]	Bit				80	225	0.0027	Decrease	2006

a This is the percent reduction attributable to the existing pollution controls and the technology.
b This is the percent reduction attributable only to the technology.
c In EPA's modeling, is it appropriate for an economic forecast to assume an improvement in costs over time (such as through technology cost reductions or through future technology innovation).
d CESP-represents cold-side electrostatic precipitator
e HESP-represents hot-side electrostatic precipitator
f Measurements of the Hg content in the coal and in the flue gas upstream of the plant's ESP have not been made.

The ECO process is currently being commercially demonstrated in a 50-MW slipstream unit at First Energy Corporation's R.E. Burger Plant in Shadyside, Ohio. Previously, ECO was pilot tested in a 1-MW slipstream unit at the same plant. Commercial demonstration testing is planned to complete in the first quarter of 2005. Based on this project, Powerspan will offer commercial ECO systems with industry standard guarantees and warranties by the beginning of 2006.

It is estimated that the capital cost of the multipollutant ECO process will be $225/kW and the operation and maintenance costs will be $0.0027/kWh. These are the estimated costs for cold-side ESP application based on the experience at the Burger Plant. The cost for fabric filter and hot-side ESP applications are expected to be similar to cold-side ESP application. To estimate the cost effectiveness of the process for Hg removal, it is estimated that the variable cost of Hg removal in the ECO process is $800 per pound of Hg, including the sorbent media and its disposal. The costs are expected to decrease over time due to technology innovations; however, the level of cost reduction has not yet been estimated.

Since the K-Fuel process reduces emissions of multiple pollutants, coal-fired facilities that will most benefit from burning K-Fuel to reduce Hg emissions include those units that will achieve the most co-benefit from SO_2 and NO_x emission reductions as well as heat rate improvements. K-Fuel will benefit units burning high sulfur bituminous coal with no SO_2 control, units burning declining supplies of Central Appalachian SO_2 compliant coal, units that have switched from bituminous to subbituminous coal to meet the Title IV Acid Rain requirements with a resulting loss in generating capacity, units with no post-combustion SO_2 or NO_x control, and small generating units that are searching for low capital cost Hg control. K-

Fuel can also be burned in units currently burning subbitminous coal and lignite, the feedstocks for K-Fuel.

K-Fuel is a commercially viable pre-combustion solution and proven technology for western coal to reduce Hg emissions from coal-fired power plants. K-Fuel accomplishes Hg reduction through its coal beneficiation process. In effect, by combusting K-Fuel the utility is achieving Hg reduction for free since Hg removal has already occurred during the K-Fuel process prior to combustion by a utility.

Table 4 below provides laboratory data for various feedstocks of sub bituminous coal, along with the corresponding reduction in Hg, increase in heat rate (Btu), and reduction in moisture content achieved by the K-Fuel process. The information presented demonstrates that the effectiveness of the process is dependent upon the properties of the unique coal feedstock.

To date, the K-Fuel pre-combustion process has not been optimized for Hg emission reduction but is a co-benefit of the pre-combustion process. In Table 4, the amount of Hg removal listed is the amount of Hg reduced in the coal prior to combustion and does not consider the potential additional reductions from existing control technologies (e.g., electrostatic precipitators, fabric filters, etc.). As a result, the Hg reduction numbers below are a beginning point for the ultimate Hg reduction achievable when burning K-Fuel, not accounting for plant specific characteristics.

A facility knows when it purchases K-Fuel how much Hg has already been removed and what amount of Hg is in the K-Fuel prior to combustion. Additional Hg removal above that already achieved in the K-Fuel will be dependent upon unit specific characteristics such as installed pollution control devices and boiler characteristics, as mentioned below.

Table 4. Emissions Reductions from Laboratory Tests using F-Fuel Process

Coal[a] ID	Coal As Rec. Moisture Percent	Coal As Rec. Btu/Lb	Coal As Rec. Hg lbs/TBtu	K-Fuel As Rec. Moisture Percent	K-Fuel As Rec. Btu/Lb	K-Fuel Hg lbs/TBtu	Moisture Removal Percent	Btu Increase Percent	Total Mercury Removal Percent
Coal 1	31.06	8520	1.98	6.06	11667	0.63	80	37	68
Coal 2	27.00	8969	24.17	5.74	11683	3.75	79	30	85
Coal 3	28.41	8536	12.58	6.46	11331	3.10	77	33	75
Coal 4	32.04	7903	7.99	7.06	11162	1.84	78	41	77
Coal 5	31.72	8126	6.30	8.00	11091	2.30	75	37	63
Coal 6	30.93	8235	3.51	6.91	11149	2.02	78	35	42
Coal 7	31.20	8032	4.05	7.09	10535	1.93	77	31	52

[a] Subbituminous coals were used for all of the laboratory tests.

K-Fuel does not impose any installation, capital, or operating costs in addition to the cost of K-Fuel per ton to achieve Hg reduction since Hg reduction is already achieved in K-Fuel prior to combustion in a coal-fired unit. As a solid coal fuel, K-Fuel will not negatively impact system components or byproducts since there are no chemicals, additives, or other substances added to the combustion process, flue gas, or to the K-Fuel itself to enhance Hg removal Currently, KFx conservatively estimates that K-Fuel will be sold for $33 per ton (including transportation costs), though market conditions and other factors may impact the price.

In June 2004, KFx announced its purchase of the Fort Union mine site near Gillette, Wyoming as the location for a commercial K-Fuel production facility. The site includes approximately 1,000 acres of land, a rail loop with load out facilities, a coal crusher, related buildings, water disposal wells and about 500,000 tons of remaining coal reserves. Private money is fully funding the project and the Wyoming Department of Environmental Quality (WYDEQ) has finalized all permits necessary for construction. The final air quality permit was granted from WYDEQ on November 8, 2004 and ground was broken on the site November 10, 2004. Concrete foundations have begun being poured as of December 2004. Fabrication of the major process components of the facility is near completion.

The feedstock coal to produce K-Fuel will be purchased from adjacent mines in the Powder River Basin. Initial output from the facility will be 750,000 tons per year and two-thirds of the output has been pre-sold with the remaining portion to be used for test burns to facilitate additional markets for K-Fuel. The K-Fuel production facility is expected to be in commercial operation in the summer of 2005. The facility can be expanded to produce up to 8 million tons per year of K-Fuel and KFx expects that with the first commercial plant in operation the development of future plants will be accelerated. KFx is examining potential commercial sites in Wyoming, Alaska, South Dakota, and other locations for additional K-Fuel production facilities. KFx plans to own and operate the K-Fuel production facilities, as well as license K-Fuel technology to third parties in the U.S. and internationally.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5472) noted that its commitment to environmental stewardship led it to participate as a partner with Sorbent Technologies Corporation and others in a U.S. Department of Energy (DOE) co-funded project to test an advanced halogenated activated carbon. The test objective was to determine the Hg removal performance and relative costs of sorbent injection for advanced sorbent materials in a large-scale field trial. One of the sites tested was the commenter’s St. Clair Power Plant Unit 1 (STCPP U1) with a cold-side electrostatic precipitator (ESP) using subbituminous coal, or a blend of subbituminous and bituminous coal. STCPP U1 is nominally 150 MW, but a completely split duct configuration allows testing to be completed on half of the flue gas stream, without resorting to the uncertainty

of slipstream configurations.

The commenter offered STCPP U1 to testing for several reasons. The majority of Hg-related testing done previously was completed on units burning either bituminous, subbituminous, or lignite coals. Since most of the commenter's units burn a blend of bituminous and subbituminous coals, it was interested in improving the understanding of the effect of these blends on the ability to control Hg emissions. STCPP U1 an effectively burn 100 percent subbituminous and blends up to 70 percent subbituminous and 30 percent bituminous. This unit could provide the opportunity to test either 100 percent subbituminous or the blended fuel.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5472) was concerned about the ability of normal sized ESPs to remove the additional particulate loading resulting from injection of sorbents. STCPP U1 is equipped with a 700 SCA (specific collection area) ESP, which is about three times larger than the average sized ESP. Not knowing how much sorbent would be injected or the ability of the ESP to remove particulate under the injection conditions, this unit's ESP could be expected to handle any possible additional loading. This means that particulate removal would not be expected to limit testing for Hg removal even at higher injection rates.

In addition, the commenter believed that this testing opportunity would provide some insight into the balance-of- plant impacts it might expect if using sorbent injection as an emission control technology at this or other coal-fired boilers.

Baseline testing and parametric testing demonstrated that B*PAC™ could be expected to provide the best results of the sorbents tested, even at a lower injection rate of 3 lbs/Macf. The final step of this test was to inject B*PAC at 3 lbs/Macf for a 30-day period, while the boiler operated under normal (varying) load conditions. Over the 30-day test period, the sorbent injection equipment constructed for the test was able to adequately follow the boiler load swings and maintain a consistent injection rate. The Hg removal rate averaged 93 percent over the 30 day period. The commenter reported that these promising results encourage additional testing for longer duration under more challenging conditions.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5472) noted that longer testing periods (minimally one year) are required to hopefully identify any unintended and unanticipated consequences resulting from the operation of this and other technologies. Cumulative effects on collection equipment or other downstream equipment not identified in a 30-day test could be identified after longer term operation, as has been experienced with other control technologies. Identification of an unanticipated consequence after a commitment to a particular technology puts the electric supply at risk. The commenter believes that this is an unacceptable result of rushing a little-tested technology into operation. A technology must be tested under various fuels and operating conditions to validate commercial viability. One 30-day test cannot provide the operational assurances necessary to ensure the performance and reliability required of electric generating units.

The commenter reported that the particulate control equipment was never expected to be a challenge or represent a normal operation during this test. This unit was chosen, in part, because of an equipment configuration that would eliminate particulate collection as a concern. The ESPs on STCPP U1, however, approach 3 times the collection capability of a normal electric generating unit ESP. Additional testing is required to demonstrate what operational impacts might be expected on smaller ESPs (<250 SCA) and what equipment and operational modifications might be required for long-term operation of sorbent injection technologies.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5472) reported that much of the industry's fly ash is currently used productively for commercial uses. The B-PAC sorbent used in this test makes fly ash unusable as a concrete additive, which necessitates landfi1l disposal of a previously useful byproduct. There is a need to develop and then conduct similar tests with "concrete-friendly" sorbents which will keep these productive uses for fly ash viable.

Because of the short-term nature of this test, there is a still need to further investigate equipment risks, such as potential corrosion in ductwork and gas handling equipment and the possibility of contamination issues in areas of fly ash hideout.

The ultimate fate of halogens, including bromine, in the flue gas stream is a continuing area of concern. Any concerns about the possible formation of toxic byproducts in flue gas stream must be thoroughly investigated and dispelled before this technology can be widely deployed. There have only been preliminary tests conducted in coal-fired electric generating boiler flue gas streams, and this issue requires significantly further research.

In addition to these specific comments offered related to the company's experience testing Brominated activated carbon injection, the commenter also supports the comments submitted by the Edison Electric Institute (EEI), the Utility Air Regulated Group (UARG), and the Electric Power Research Institute (EPRI).

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5496) is an advocate of public policies that are protective of public health and is prepared to make reasonable additional reductions in power plant Hg emissions. This commenter has been a strong advocate for the Minnesota Mercury Contamination Reduction Initiative and achieved about 17 percent reduction in Hg stack emissions in 2000 compared to 1990 levels through optimizing fuel sourcing and plant operation. The commenter's coal units are also over 70 percent wet scrubbed for particulate and sulfur dioxide removal, which combined with other voluntary Hg reduction activities has reduced base line emissions relative to 1990 and compared to other utility units. Consequently, an equitable allocation of Hg reduction requirement stringency, either through unit specific requirements or cap-and-trade program allowance allocation methodology is important for assuring reasonable credit for early action. The commenter supports an equitable cap-and-trade approach as the preferred option for regulating electric power sector Hg emissions, as that provides the most flexibility for achieving compliance using new and often unproven technology.

Response:

EPA is finalizing a cap-and-trade approach under section 111. See final rule preamble for rationale.

Comment:

One commenter (OAR-2002-0056-5496) notes that the technology EPA and other modelers have presumed to be effective for achieving high percentages of Hg removal in their Integrated Planning Model involves use of activated carbon injection followed by particulate collection. However, over 70 percent of this commenter's coal generation is operated with wet scrubbers, providing for particulate removal while delivering sulfur dioxide emission reductions. The commenter has injected activated carbon into its wet scrubbers and found only small improvements in Hg removal (zero to 30 percent) over the realm of typical activated carbon injection rates. The wet scrubbers create a near-saturated flue gas with entrained water droplets, making operation with a fabric filter downstream of the scrubber impractical due to filter plugging. The flue gas temperature upstream of the wet scrubbers is too high for reliable filter operation. Consequently, units operating with existing wet scrubbers are not amenable to retrofit of activated carbon and fabric filter technology.

Response:

EPA is finalizing a cap-and-trade approach under section 111. See final rule preamble for rationale. Under a cap-and-trade approach the commenter will have flexibility in its compliance options including buying allowances. EPA also notes that ACI with a pulse-jet fabric may be installed upstream of wet scrubber. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5496) notes that IPM modeling presumes uniform control costs and percent Hg reductions for coal units that are targeted to retrofit activated carbon injection and fabric filters, without sufficient consideration of unit size (economy of scale), coal type (concentration and species of Hg emitted) or current emission rates. Incremental reductions in the targeted Hg emissions cap should be expected to give increasingly higher Hg reduction costs in terms of dollars per pound Hg removal when performing modeling. For example, the Table 1–Summary of CCAP Power Sector Modeling (Federal Register Volume 69 No 230 page 69868) presents a linear incremental cost as the Hg cap is reduced from 15 tons to 7.5 tons over a regime of affected units that would be expected to exhibit higher costs due to economy of scale or lower Hg content coal. Linear consideration of unit control retrofit costs affirms the IPM does not adequately address incremental control costs.

Response:

The commenter is incorrect that IPM modeling uses uniform control costs and percent Hg reductions. Hg-specific control costs (ACI) vary by size of the unit and coal type burned. Hg removal varies by coal type and control type. In addition scrubbers and SCR also consider economies of scale. See IPM documentation in docket for further discussion of control cost and performance assumptions.

Comment:

One commenter (OAR-2002-0056-5561) stated that the demand growth assumptions used in our sensitivity analyses, published in the NODA, appeared to be reasonable. The average growth rate of 1.8 percent per year was identical to the latest demand forecast published in Energy Information Administration's 2005 Annual Energy Outlook. Demand forecasts used by other analysts such as Cinergy (2.3 percent per year) may be too high. The natural gas price assumptions used in the commenter's sensitivity analyses, on the other hand, may be somewhat low. Use of higher gas price assumptions would be expected to raise system costs in both the base and policy cases. It was not clear what effect higher gas prices would have on the incremental cost of the various Hg policy scenarios that were investigated. However, the sensitivity runs the commenter evaluated with higher gas prices and load growth assumptions resulted in very modest increases in system costs (roughly 1 percent) for the increasingly tighter second Phase Hg caps over the system cost increases under increasingly stringent scenarios using our original lower gas price and load growth assumptions. (See Document ID No.

OAR-2002-0056-xxxx submitted on June 29, 2004 for details on the Air Quality Dialogue analyses.)

Response:

As discussed in EPA's IPM documentation, EPA uses its natural gas prices and demand forecasts different from those of EIA. EPA has performed a sensitivity analysis examining the impact of uses EIA natural gas prices and electric growth projections. See chapter 7 of final rule CAMR RIA.

Comment:

One commenter (OAR-2002-0056-5521) provided the following information:

Limestone Forced Oxidation (LFSO)

This cost estimate was for the cost of installing, operating, and maintaining LFSO only.

Merrimack Station

Cost Estimate (1995 Dollars)	MK 1 (113 MWe)	MK2 (320 MWe)
Capital	$48/kW ($54,240,000)*	$250/kW ($80,000,000)*
Fixed O&M	$16.0/kW/yr ($1,808,000/yr)	$10.0/kW-yr ($3,200,000/yr)
Variable O&M	1.1 mills/kWh ($868,733/yr)	1.1 mills/kWh ($2,527,360/yr)
Total Annual**	10.26 mills/kWh ($8,100,733/yr)	5.98 mills/kWh ($13,727,360/yr)

* This capital cost estimate included the costs for a reagent feed system, a wet SO2 removal system, a flue gas handling system, a waste/by-product handling system and support equipment (exhaust stack) but didn't include a cost estimate for replacement of primary fans if required.

** Used 2002 MWh to estimate cost in mills/kWh.

Powdered Activated Carbon Injection

This cost estimate was for the cost of installing, operating, and maintaining the Powdered Activated Carbon Injection only. Costs were calculated using U.S. EPA's and U.S. DOE's Mercury Control Performance and Cost Model (MCPCM), September 30, 2000.

Merrimack Station

Cost Estimate (1999 Dollars)	MK 1 (113 MWe)	MK2 (320 MWe)
Capital	$8.49/kW*** ($ 959,370)	$5.97/kW*** ($1,910,400)
Fixed O&M	$3.64/kW/yr ($411,320/yr)	$1.64/kW/yr ($524,800/yr)

Cost Estimate (1999 Dollars)	MK 1 (113 MWe)	MK2 (320 MWe)
Variable O&M	1.10 mills/kWh ($868,733/yr)	1.10 mills/kWh ($2,527,360/yr)
Total Annual**	1.74 mills/kWh ($1,375,990/yr)	1.41 mills/kWh ($3,243,200/yr)

** Used 2002 MWh to estimate cost in mills/kWh.

*** Total Control Capital Costs including process equipment, field materials, field labor, indirect field costs, engineering and home office overhead/fees, process contingency, project contingency, and general facilities.

Powdered Activated Carbon Injection & Spray Cooling

This cost estimate was for the cost of installing, operating, and maintaining the Powdered Activated Carbon Injection and Spray Cooling system only. Costs were calculated using U.S. EPA's and U.S. DOE's Mercury Control Performance and Cost Model (MCPCM), September 30,2000.

Merrimack Station

Cost Estimate (1999 Dollars)	MK 1 (113 Mwe)	MK2 (320 MWe)
Capital	$24.63/kW***($2,783,190)	$17.20/kW***($5,504,000)
Fixed O&M	$5.58/kW/yr ($630,540/yr)	$2.99/kW/yr ($956,800/yr)
Variable O&M	1.13 mills/kWh ($900,323/yr)	1.14 mills/kWh ($2,619,264/yr)
Total Annual**	2.29 mills/kWh ($1,809,182/yr)	1.80 mills/kWh ($4,126,464/yr)

** Used 2002 MWh to estimate cost in mills/kWh.

*** Total Control Capital Costs including process equipment, field materials, field labor, indirect field costs, engineering and home office overhead/fees, process contingency, project contingency, and general facilities.

Powdered Activated Carbon Injection & Pulse Jet Fabric Filter

This cost estimate is for the cost of installing, operating, and maintaining the Powdered Activated Carbon Injection, and Pulse Jet Fabric Filter system only. Costs were calculated using U.S. EPA's and U.S. DOE's Mercury Control Performance and Cost Model (MCPCM), September 30, 2000.

Merrimack Station

Cost Estimate (1999 Dollars)	MK 1 (113 Mwe)	MK2 (320 MWe)
Capital	$50.38/kW*** ($5,692,940)	$40.00/kW*** ($12,800,000)
Fixed O&M	$8.68/kW/yr ($980,840/yr)	$5.73/kW/yr ($1,833,600/yr)
Variable O&M	1.15 mills/kWh ($908,221/yr)	1.15 mills/kWh ($2,642,240/yr)
Total Annual**	3.11 mills/kWh ($2,458,355/yr)	2.51 mills/kWh ($5,755,840/yr)

** Used 2002 MWh to estimate cost in mills/kWh.
*** Total Control Capital Costs including process equipment, field materials, field labor, indirect field costs, engineering and home office overhead/fees, process contingency, project contingency, and general facilities.

Powdered Activated Carbon Injection, Spray Cooling & Pulse Jet Fabric Filter

This cost estimate was for the cost of installing, operating, and maintaining the Powdered Activated Carbon Injection, Spray Cooling, and Pulse Jet Fabric Filter system only. Costs were calculated using U.S. EPA's and U.S. DOE's Mercury Control Performance and Cost Model (MCPCM), September 30, 2000.

Merrimack Station

Cost Estimate (1999 Dollars)	MK 1 (113 Mwe)	MK2 (320 MWe)
Capital	$66.53/kW*** ($7,517,850)	$51.23/kW*** ($16,393,600)
Fixed O&M	$10.62/kW/yr ($1,200,060/yr)	$7.08/kW/yr ($2,265,600/yr)
Variable O&M	1.19 mills/kWh ($939,811/yr)	1.19 mills/kWh ($2,734,144/yr)
Total Annual**	3.66 mills/kWh ($2,891,660/yr)	2.89 mills/kWh ($6,639,104/yr)

** Used 2002 MWh to estimate cost in mills/kWh.
*** Total Control Capital Costs including process equipment, field materials, field labor, indirect field costs, engineering & home office overhead/fees, process contingency, project contingency, and general facilities.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's

Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5456) noted that the DOE National Environmental Technology Laboratory (NETL) recently issued their next round of awards for testing of advanced Hg reduction technologies at coal-fired power plants. This testing is to take place in the 2005-2007 time frame. The point of this discussion is to note that scientific testing and research on Hg monitoring and control equipment are still continuing and will continue for the next few years. If the technologies related to Hg issues were sufficiently demonstrated, there would be no need for continuation of the testing programs of this nature.

The commenter has been participating in various Hg projects that attempt to present a better understanding of various issues related to Hg emissions from the combustion of coal in electric utility steam generating units, specifically those burning PRB subbituminous coal. These projects involve studying Hg emissions control technologies and Hg emissions monitoring.

The DOE/NETL announcement of the awards states "With an eye on future federal regulations aimed at reducing Hg emissions, the DOE has selected six additional projects as part of a DOE research program to advance the technical readiness of Hg control options for the Nation's fleet of coal-fired power plants. The six projects in this next round of awards build on last year's selection of eight projects, and will verify technology performance, evaluate costs, and assess balance-of plant impacts. The projects will field test advanced, post-combustion technologies involving all coal types at utilities using pulverized coal or cyclone-boiler configurations, and focus on technologies capable of removing Hg from flue gas containing higher concentrations of elemental Hg. The technologies include sorbent injection, wet flue gas desulfurization systems enhancement, and combustion optimization. Both rounds of selections are aimed at meeting the Energy Department's near-term goal of having technologies that can capture 50-70 percent of Hg emissions ready for commercial demonstration by 2005 for power plants burning bituminous coal, and by 2007 for those that burn low-rank coals and blends. The Energy Department has set a longer term goal of having technologies that can achieve 90 percent Hg reduction for all fuel types ready for commercial demonstration by 2010, and is also looking to reduce the cost of Hg control by 25-50 percent over baseline, activated-carbon costs, which range from $50,000-$70,000 per pound of mercury removed."

The important statement in the above is that DOE/NETL is seeking to be ready for commercial demonstration, not commercial use, of Hg control by 2005 for bituminous coals, and 2007 for low rank coals (lignite and subbituminous coal).

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired

Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5458) noted that in the January Federal Register proposal, EPA fails to acknowledge the ongoing work being conducted under the U.S. Department of Energy/National Energy Technology Laboratory (DOE/NETL) Mercury Control Technology Research Program on coal fired power plants. Four full-scale demonstration projects have tested the effectiveness of carbon injection in tandem with conventional criteria air pollution control devices currently in use at utilities. Specifically, the E.C. Gaston plant in Alabama burning low sulfur bituminous coal achieved greater than a 90 percent Hg removal rate using carbon injection, along with a hot side electrostatic precipitator (ESP) and a compact hybrid particulate collector (COHPAC) baghouse for particulate control. The Brayton Point plant in Massachusetts burning low sulfur bituminous coal achieved a 90 percent Hg removal rate using carbon injection in combination with a cold-sided ESP. The Pleasant Prairie plant in Wisconsin burning sub-bituminous coal achieved a 65 percent removal rate using carbon injection with a cold-sided ESP. Significantly, the E.C. Gaston Plant achieved a high Hg removal rate and used considerably less carbon injection as a result of the addition of a COHPAC baghouse or fabric filter in comparison to the other projects. The additional pollution control equipment has the potential to significantly increase Hg removal rates from sources burning both bituminous and sub-bituminous coal.

Real reductions for both Hg and sulfur can be achieved when Utility Units install wet scrubbers or spray dryer adsorbers, in conjunction with fabric filters. According to the Information Collection Request III data, the lowest emissions of Hg and sulfur were achieved when these pollution control devices were used. The Department analyzed emissions data from Utility Units in eight states surrounding New York. This analysis showed that the Utility Units achieving the greatest Hg reduction were ones utilizing fabric filters. Several of the better controlled units have ESPs but also used a wet scrubber for sulfur control. The Department has experience with municipal waste combustors (MWCs) in New York that use carbon injection in combination with fabric filters or ESPs. These MWCs equipped with carbon injection and ESPs achieve Hg emissions reductions of at least 85 percent. MWCs equipped with carbon injection and fabric filters achieve reductions greater than 90 percent. Mercury is predominantly emitted in the oxidized form by MWCs.

The Supplemental Notice and a letter to the Air Docket from the DOE (Document ID No. OAR-2002-0056-0044) describe the need for six years to adequately conduct a commercial demonstration of Hg controls. The Department believes that this long time frame is not justifiable and it appears that EPA is attempting to selectively develop time lines to justify a cap-and-trade program. Upon closer examination, the average six year figure includes a pre-award period greater than 12 months, with each full-scale demonstration project taking another 12 months, and allows for inflation during the operation and reporting time line by including the time it takes to prepare a report on the project. A more realistic value for commercial demonstration is in the range of three to four years, especially in light of all of the full-scale Hg demonstration projects already completed or currently being conducted.

The goal of the DOE/NETL Mercury Control Technology Research Program is for these

technologies to be available for bituminous sources by 2005 and for lignite and sub-bituminous sources by 2007. The program also describes the commercial development of advanced Hg control technology that will achieve a 90 percent Hg reduction for all coal types by 2010. In fact, the field testing of this technology at a number of coal fired units was already underway in 2003. If these goals are attained, widespread commercial deployment of extremely efficient Hg air pollution control technologies could begin to occur in 2008 for bituminous sources and 2011 for lignite and sub-bituminous sources.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5446) believed that the variety of input assumptions, particularly in regard to costs and Emission Modification Factors (EMF), used in the modeling analysis highlight the uncertainty associated with the cost and performance of Hg control technologies. Given the limited data available, this uncertainty is to be expected and simply reflects limited knowledge in the area. Therefore, any final rule must be sufficiently flexible to accommodate the high degree of uncertainty inherent in the available data. The commenter believed that a national "cap and trade" based regulation with appropriate caps and timing will provide an important component of flexibility and will help the EPA address this inherent uncertainty.

Furthermore even the range of assumptions used in the commentator's models only indicates that there is uncertainty in the cost and performance of a typical plant and typical coal. The models do not account for the wide variability of coals and process conditions that can result in significant differences in performance between two plants with nominally similar coals and identical control technology. It is important that the EPA recognize that the performance of the average plant does not represent the behavior of the fleet. In order to understand the implications of the regulation EPA must undertake some form of probability analysis that considers natural variability in coal properties and unit performance and assesses their impact on the modeled results.

Failing to account for variability in fuel type and unit operation will make it difficult if not impossible for EPA to establish limits that are technically achievable for all affected units.

Response:

EPA is finalizing a cap-and-trade approach under section 111. See final rule preamble for rationale. EPA's IPM modeling does take into account some extent variability of coals and control configurations. IPM provides for extensive modeling of the coal sector, where coals can be selected by mercury content and sulfur content. For further discussion see EPA's IPM documentation in rulemaking docket.

Comment:

One commenter (OAR-2002-0056-5510) was concerned that the various input assumptions used in the commenters' modeling analysis do not account for the wide variability of coals and process conditions encompassed by the full fleet of US utility boilers. Failing to account for variability in fuel type and unit operation will make it difficult if not impossible for EPA to establish limits that are technically achievable for affected units. The commenter suggested, phased alternative to establishing a national cap and trade program, as articulated in comments dated May 14, 2004, and again in these comments in response to II.B.4.g, would address the variability concern through ensuring a far better database than currently exists.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale.

Comment:

One commenter (OAR-2002-0056-5488) states that activated carbon injection (ACI) has been extensively tested in several full-scale tests and pilot-scale tests and in a recent long-term test performed at the Gaston power plant. Full scale testing performed by ADA-ES along with testing performed by EPRI showed that high levels of Hg control, at least 90 percent, could be achieved on a cost-effective basis at coal-fired power plants with ACI regardless of the rank of coal burned, with the utilization of modern particulate matter control equipment (i.e., a fabric filter or a polishing baghouse downstream of an electrostatic precipitator). Long-term tests of ACI outfitted with a small baghouse downstream of a hot-side ESP have continued at the Gaston power plant, which burns bituminous coal. This combination effectively addresses problems with carbon-contamination of fly ash that can occur when activated carbon injection is used with an ESP alone. It is also quite viable for retrofit applications, because of the compact size of the polishing baghouse. The tests conducted at Gaston show that such units can achieve greater than 90 percent Hg control on a long-term average basis, with appropriately sized baghouses and activated carbon injection rates. The Gaston investigators, from ADA-ES, EPRI and DOE, conclude that "activated carbon injection systems are simple, reliable and commercially available." The conclusion that activated carbon injection is commercially available today has also been affirmed by the national trade association of control technology vendors.

Beyond activated carbon injection, EPA neglected to seriously consider several other highly effective approaches that are available for reducing Hg emissions from existing coal-fired power plants. These include Electro-catalytic oxidation™, advanced dry FGD, coal blending for plants burning sub-bituminous coal, injection of non-carbon based sorbents, and pre-combustion coal scrubbing to increase combustion efficiency of lignite and sub-bituminous coals while simultaneously removing Hg, N, and S before the coal is burned.

Advanced dry FGD technology is widely used in Europe and has been demonstrated at Roanoke Valley Energy's 55 MW bituminous coal fired Unit 2 with Hg removal in excess of 95 percent. Two companies actively marketing advanced dry FGD are F.L. Smidth AirTech,

which is marketing their Gas Suspension Absorber (GSA) as a retrofit with an existing ESP or Pulse Jet fabric filters; and RJM-Beaumont which is marketing their Rapid Absorption Process (RAP) as a multipollutant (SO_2, PM and Hg) control technology.

Electro-catalytic oxidation™ (ECO) technology has been demonstrated on a 2000 scfm pilot at First Energy's Burger Plant in Akron, OH, which has been operating since March 2002. Pilot test results indicate 80-90 percent Hg removal under any inlet condition. Early results from a 50 MW commercial demonstration system at Burger indicate similar performance to the pilot tests. A 510 MW ECO system is planned for installation at AmerenUE's Sioux Plant in Missouri following successful completion of the Burger demonstration.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5502) referenced technological improvement. The history of technology development, including that of environmental controls, clearly shows that technology does improve with time. Examples (see Document ID No. OAR-2002-0056-5502) are provided to support a modest improvement rate of 2.5 percent per year, which is one of the several cases (along with quicker and slower growth cases) modeled by Charles River Associates for the EEI and the commenter's submittals in June 2004. Because technology improvement affects the control technology choices made by power plants in the model analysis, and therefore provides a more realistic prediction of the industry's likely response to the various proposed regulatory scenarios, the commenter believed it is important, and very appropriate, to include cost reductions and/or performance improvements in an economic model.

Control considerations for modeling. The detailed comments provide information on the topics identified in EPA's question (under §II.B.4.c)-timeline for commercialization, cost, balance of plant impacts, and control performance. While the commenter could not comment on commercialization issues as they do not own and operate power plants, they have provided the conditions they believe are needed for Hg controls to be considered "commercially available." These include consistent, predictable results from the approximately 30 field tests sponsored by DOE and the co-funded by the industry and the commenter, as well as enough truly long-term tests (e.g., 12-18 months) to ensure that the industry understands how to operate the equipment reliably and manage and plant impacts that may be caused by the technology. A technology that gets this far is then ready to be procured by the first users, with full implementation by al plants that select this technology several years later.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's

Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005). EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of second ACI option using advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis.

Comment:

One commenter (OAR-2002-0056-5505) stated that the Department of Energy (DOE) National Environmental Technology Laboratory (NETL) recently issued their next round of awards for testing of advanced Hg reduction technologies at coal-fired power plants. This testing is to take place in the 2005-2007 time period. The point of this discussion is to note that scientific testing and research on Hg control technologies are still continuing and will continue to do so now and for the next number of years. If the technology were sufficiently demonstrated, there would be no need for continuation of the testing programs of this nature.

The DOE/NETL announcement of the awards (5 November 2004) states "With an eye on future federal regulations aimed at reducing Hg emissions, the DOE has selected six additional projects as part of a DOE research program to advance the technical readiness of Hg control options for the Nation's fleet of coal-fired power plants.

The six projects in this second round of awards build on last year's selection of eight projects, and will verify technology performance, evaluate costs, and assess balance-of plant impacts. The projects will field test advanced, post-combustion technologies involving all coal types at utilities using pulverized coal or cyclone-boiler configurations, and focus on technologies capable of removing Hg from flue gas containing higher concentrations of elemental Hg. The technologies include sorbent injection, wet flue gas desulfurization systems enhancement, and combustion optimization.

Both rounds of selections are aimed at meeting the Energy Department's near-term goal of having technologies that can capture 50-70 percent of Hg emissions ready for commercial demonstration by 2005 for power plants burning bituminous coal, and by 2007 for those that burn low-rank coals and blends. The Energy Department has set a longer term goal of having technologies that can achieve 90 percent Hg reduction for all fuel types ready for commercial demonstration by 2010, and is also looking to reduce the cost of Hg control by 25-50 percent over baseline, activated-carbon costs, which range from $50,000 to $70,000 per pound of mercury removed."

The important statement in the above is that DOE/NETL is seeking to be ready for commercial demonstration, not commercial use, of Hg control by 2005 for bituminous coals, and 2007 for low rank coals (lignite and subbituminous coal).

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's

Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

The commenter (OAR-2002-0056-5519) stated that information referred to earlier demonstrated that Hg controls were commercially viable and cost effective:

- Low NO_x burners, activated carbon injection (ACI), selective catalytic reduction (SCR), and acid gas controls [including Lime Stone Forced Oxidation (LFSO)] and wet Electrostatic Precipitators (wet-ESPs) for reducing Hg emissions, were already commercially available and ready for installation on all coal-fired electric steam generating units for all types of coal, and

- The maximum total control costs for achieving 90 percent Hg removal efficiency on a 100 MW coal-fired electric steam generating unit was less than $6 per month to a homeowner who used 500 kWh per month of electricity.

(Note that this worst case total capital cost estimate for a 100 MW unit to install LSFO with a new stack and a balanced draft conversion of the boiler was $65.2 million dollars, 2002 dollars). More recent control cost estimates in 2003 dollars calculated for new IPM modeling indicated that the cost to install LFSO for 500 MW unit were as follows: total capital cost=$236 million, fixed O&M=$9.16 per kW/yr and variable O&M=$1.08 mills/kWh. Recent health data indicated that if plant specific, Hg controls were not required and not installed on coal-fired electric steam generating units, the same homeowner would be required to expend numerous times more in healthcare costs. Simply put, air pollution controls capable of achieving 90 percent Hg removal efficiency could be installed on all coalfired electric steam generating units 100 MW or larger at an average monthly cost to the homeowner that is much more cost effective than dealing with its environmental and health cost consequences.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5497) stated that they do not believe that EPA's modeling of the power sector has omitted any control technologies that are reasonably likely to be available or likely to be commercialized within the time frame for decision and implementation of Hg control technologies, consistent with the timelines envisioned by the Clear Skies Initiative. The preceding response discussed the problems with modifying an ESP to increase collecting plate area when ACI is employed and with the widespread retrofit of fabric filters.

While promoted vigorously by vendors with a commercial interest in such technologies, halogenated activated carbons, such as one containing bromine or iodine, are technologies that should not be considered commercially available or proven. While there has been a single test with brominated ACI that involved one-half of the flue gas stream from a 150 MW unit that indicated this might eventually hold some promise, innumerable uncertainties remain with this technology. A 30-day test period is simply insufficient to understand the long-term effects that might be encountered when such potentially corrosive substances are injected into a utility boiler. There would likely be effects on the ability to sell or dispose of fly ash, corrosion on ductwork and/or collecting plates, and possibly the production of potentially harmful by-products such as dioxin.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

4. CATF and Cinergy both modeled more stringent MACT-type options. CATF assumed that ACI would be available in 2005 for all coal types. Cinergy assumed that ACI would be available in 2005 for all coal types in one scenario and in 2010 for all coal types for another scenario. EPA assumed commercial application only beginning in 2010 with 70-90 percent removal levels. The year of availability for ACI makes a large difference in the projected impacts of a MACT-type option. What assumptions for ACI availability are most appropriate to consider in a modeling analysis, at what quantities, for what coal types, and why?

Comment:

One commenter (OAR-2002-0056-5464) reviewed the IPM modeling summaries highlights as an important fact: the results are only as good as the variables used in the model. That is, the inputs and assumptions used in the model are not only critical to its accuracy and success but, more importantly, assumptions about availability, control efficiency and cost (both capital and operation and maintenance costs) predetermine its results. Unfortunately, they believed several of the assumptions and inputs described in the NODA are fundamentally flawed and account for unrealistic results. For example, the Cinergy model assumes that ACI would not be available until 2010 (five years from now). This is erroneous, in that ACI is available now. Further, if a unit has difficulty complying with the MACT limit by 2008, using ACI and the existing control system on the unit, then the Clean Air Act, under Sections 112(i)(3) and 112(i)(4), contains provisions that could offer additional time. Because ACI is available now and the Clean Air Act provides for extensions for more substantial control device addition or replacement, the commenter does not agree there would be a need for power plants to shut down for as long as two years, as the Cinergy model assumes. In fact, installation of ACI requires little down time and may be sufficient on many plants to achieve substantial Hg control. With halogenated sorbents, this may be all that is required for most plants to achieve 90 percent or more control. In cases where existing particulate control at coalfired units is poor and needs to be replaced or supplemented with more effective particulate control, the compliance period for

the rule should be adequate to avoid disruptions in power supply. If needed, more time can be allotted on a case-by-case basis, long-term shutdowns can be avoided, and any shutdowns can be planned to avoid disruptions.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5332) agreed that the year of availability of ACI as a control option for Hg is a key issue in the modeling analyses. The Agency has apparently received many comments on this issue, ranging from the view that the technology is commercially available today to the opinion that it will not be commercially available until well after 2010. The commenter does not have first-hand information with respect to the date on which ACI should be considered a commercially viable option for Hg control from coal-fired power plants. However, the commenter offers the following evidence in support of the proposition that this technology should be considered available on the earlier end of the time frame being considered, with the caveat that the effectiveness and cost of ACI in reducing Hg emissions will depend to some degree on the details of plant configuration and type of coal burned.

First, ICAC, which is the national trade association of companies that supply air pollution control and monitoring technology, has gone on record in written comments submitted to EPA, and in testimony presented at a Congressional hearing, that ACI systems are currently available, have already been used in full-scale applications for the power sector and other industrial sectors, and can be applied to any plant configuration and coal type. It can be argued that considerations of self interest may contribute to ICAC's conclusions. On the other hand, ICAC's claims that site-specific guarantees for activated carbon systems are being offered commercially in the marketplace today for many plant configurations and coal types certainly should not be ignored.

Second, a number of states, including Massachusetts, New Jersey, Wisconsin and Connecticut, have already promulgated Hg reduction requirements. In some of these states, strict Hg reduction requirements are being imposed in the 2006 to 2008 timeframe, and compliance will require use of ACI or of another approach that will achieve similar levels of reduction. In developing these regulations, the states have conducted evaluations that have lead them to conclude that activated carbon will be a commercially available option in this timeframe.

And finally, the regulations EPA promulgates will themselves play a role in driving the commercial availability of ACI and other control technologies. Relatively stringent standards will propel the commercial availability of technology, while less strict requirements will forfeit this benefit. By the same token, the more certainty the requirements offer from a legal perspective-whether by virtue of legislation or rules that are likely to withstand legal

challenge-the more likely the requirements will be to drive the early commercial availability of controls.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5475) noted that the utility of using ACI as a control method was discussed in the NODA. The acting principle of ACI is that by injecting carbon additional Hg is captured in the existing particulate control device in a manner similar to how the particulate form of Hg in the gas stream is already being captured. The commenter states that it is in favor of the use of this approach for significantly reducing Hg emissions. This technology has been used to successfully reduce Hg emissions at several coal-fired utilities across all coal types.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5475) noted that brominated activated carbon injection, a form of ACI where the carbon is combined with bromine before injection, has demonstrated 95 percent Hg removal at Great River Energy's Stanton 10 Plant. Injecting brominated activated carbon tends to convert a higher portion of the elemental Hg to the oxidized form. This is analogous to the effect naturally occurring chlorine in coal has on Hg emissions. Achieving 95 percent removal at the Stanton 10 Plant is significant since it burns lignite coal, which is generally recognized as the most difficult to control. Lignite is difficult to control, in part, because lignite's chlorine content is typically low. This commenter states that it does not appear that EPA has considered the impacts of the recent improvements to the ACI technology in the proposed MACT rule.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of second ACI option using advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis.

Comment:

One commenter (OAR-2002-0056-5447) said that while they remain encouraged about the potential for ACI and other Hg control technologies, the basic facts have not changed since the commenter filed its April 30, 2004, comments. No technology, including ACI, has been demonstrated to achieve the emission rate proposed under the new source MACT or NSPS regulatory schemes on a commercial scale for all but the lowest Hg content coals. No vendors of control technology are willing to guarantee Hg removal at the rates needed to achieve the proposed new source emission levels. This lack of guarantees affects financing, choice of fuel, and ultimately the economic viability of the unit. If units are not economically viable, they will not be developed and the nation's energy supply will suffer.

The commenter noted that any estimate of when Hg-specific control technologies will become commercially available remains uncertain. All technologies must be tested on a broad range of coals over longer periods of time. Balance-of-plant issues must be identified and resolved.

EPA must base its ACI availability and performance projections on realistic development estimates and not on assumptions that there will be "funding [for and the] successful implementation of an aggressive, comprehensive [ACI] research and development program at both EPA and the U.S. Department of Energy." 69 Fed. Reg. 69870, col. 2-3. EPA explained in its January 2004 white paper that implementation of such a research and development program is the basis for its projection that ACI technology will be available for commercial application after 2010 and that removal levels in the 70-90 percent range could be achievable. 69 Fed. Reg. 69870, col. 2. In fact, there is no assurance that ACI will be commercially available by 2010.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005). EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of second ACI option using advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis. Commenter is referred to the preamble for discussion of NSPS limits.

Comment:

One commenter (OAR-2002-0056-5458) contended that the results of the numerous modeling summaries provided in the NODA are only as good as the input variables. The

December 2000 finding clearly established an "appropriate and necessary" finding to reduce Hg emissions by properly developing a NESHAP for coal fired utility plants. The commenter believed the use of activated carbon injection and other alternative sorbents which will reduce Hg emissions from both bituminous and sub-bituminous coals has advanced greatly and would be available much earlier than 2010 as speculated in some of IPM runs provided in the NODA. The commenter was also concerned that the EPA did not conduct, and provide for comment, the additional modeling with the IPM to evaluate the more stringent MACT options. This was previously requested by the state environmental agency representatives who served on the Federal Advisory Committee Act Utility Workgroup.

The IPM input data comparing MACT based approaches with alternative regulatory approaches relies solely on the projected Hg reductions achieved with using activated carbon injection (ACI) or similar sorbents. The analysis presented by Cinergy used a stringent MACT value for all subcategories of coal but questioned the ability of ACI's availability by 2010. The DOE recently announced that six new projects would be in their second round of field testing for ACI and new sorbents. (This is in addition to last year's selection of eight projects by DOE.) Both rounds of testing are aimed at meeting the DOE's near term goal of having technologies that can capture 50-70 percent of Hg emissions ready for commercial demonstration by 2005 for plants burning bituminous coal and by 2007 for those burning lower rank coals and blends. By 2010, the DOE expects costs to be reduced by 25-50 percent.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5446) stated that it was worth noting that even with discrepancies in assumptions models of a stringent MACT without sub-categorization or with inadequate subcategorization, predict a dramatic decline in demand for sub-bituminous coal. For example, Cinergy modeling of a strict MACT without sub-categorization1 shows sub-bituminous and lignite plants shutting down prior to the availability of dedicated control technologies. In reality it is extremely unlikely that these plants would shut down for several years and then restart when control technology became available. They would be far more likely to switch fuels or be permanently retired. In this case the very significant declines in the use of subbituminous and lignite coals predicted would have a very dramatic impact on US electricity supplies and regional economies.

In addition, modeling by the Clean Air Task Force (CATF) of an Alternate Mercury Control Scenario with a reduced level of sub-categorization showed a 27 percent decline in sub-bituminous coal use relative to 2003.

These results demonstrate that the EPA must incorporate sub-categorization by coal rank if it is to meet its commitment of implementing a rule that ensures a level playing field for all coal types.

Response:

EPA is finalizing a cap-and-trade approach under section 111. As discussed in other comment responses, the final rule takes into account the different levels of mercury control that lignite, bituminous, and subbituminous coals can achieve and uses coal adjustment factors for determining the state emission budgets and for EPA's example allocation for States to allocate at the unit level. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Indian Country Emissions Budgets, EPA, March 2005.

Comment:

One commenter (OAR-2002-0056-5510) stated that DOE projects that ACI technology, capable of achieving a 50-70 percent reduction in Hg emissions from all coal types, will be commercially available by 2010. In this regard, assumptions may be used for modeling purposes, but those assumptions must have a rational basis, and must be conservative enough to take into account the uncertainty and variability associated with ACI controls on the full range of boilers and fuel types. The commenter referred to their supplemental Hg rule comments dated June 29, 2004:

> "A fundamental problem in developing and predicting the performance of mercury control technology is that mercury chemistry is poorly understood, particularly in context to the wide range of conditions encountered in coalfired power plants. Correlations of mercury speciation with flue gas composition are instructive, but have poor predictive power (i.e., wide confidence intervals) as discussed in the commenter's May 14 comments on the rule. These numerical correlations fail to account for such important factors as flue gas and fly ash composition, including unburned carbon, and heterogeneous gas-solid reactions between mercury and the fly ash1. Work on scientifically based (i.e., a priori) chemical models is underway, but their usefulness remains to be seen."

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5491) said that a revolution has occurred over the last year in power-plant Hg-control technology. Coal chlorine content has now been made irrelevant. Consequently, the currently-proposed Hg MACT structures, limits, and timetables

need to be radically modified.

The EPA's current MACT proposals were based on a fundamental assumption that the low chlorine content of Western subbituminous coals and lignites severely limited the performance of Hg reduction technology with these fuels.

For the traditional MACT proposal, this resulted in differing Hg emission floor limits subcategorized by coal rank.

For the cap-and-trade proposals, this resulted in differing emission-allowance allocation adjustment-factors by coal rank.

Treating the different coal ranks differently because of their chlorine contents resulted in highly divergent standards which would lead to significant marketplace inequities and distortions:

Coal Type	**Proposed Emission Standards**		**Allocation Adjustment Factors**
	Existing Plants (lb Hg/TBtus)	**New Plants (10^{-6} lb Hg/ MWh)**	
Lignite	9.2	62	3
Subbituminous	5.8	20	1.25
Bituminous	2.0	6	1

Fortunately, vast improvements in the performance and cost-effectiveness of activated carbon injection technology (ACI) for low-chlorine subbituminous coal and lignites have recently been conclusively demonstrated. Multiple DOE-co-sponsored full-scale retrofit demonstrations by different contractors of ACI with brominated carbons at plants burning low-chlorine fuels this past year consistently achieved Hg emission rates of less than 1.0 lb Hg/TBtus at very low costs. Moreover, these new brominated carbons are now commercially available for use by any plant. Consequently, the currently-proposed Hg MACT structures, limits, and timetables have to be radically modified to account for these developments.

At the very least, the MACT floor levels or adjustment factors for subbituminous coals and lignites now have to be lowered to the levels currently proposed for bituminous coals. More responsibly, subcategorized standards based in plant particulate-control equipment, rather than by coal rank, should be promulgated, with resulting MACT floor levels of 1.0 lb Hg/TBtu or below. If a cap-and-trade system is proposed instead, its 2010 cap should be in the range of 8 to 10 tons of Hg per year, not 34.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for

rationale. The final rule takes into account the different levels of mercury control that lignite, bituminous, and subbituminous coals can achieve using existing NOx and SO_2 controls and uses coal adjustment factors for determining the state emission budgets and for EPA's example allocation for States to allocate at the unit level. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Indian Country Emissions Budgets, EPA, March 2005.

Comment:

One commenter (OAR-2002-0056-5488) noted that EPA's January 30, 2004 proposed rule making erroneously and unlawfully found that ACI for Hg control at EGUs is "not available on a commercial basis." As discussed in the commenter's June 27, 2004, comments, this assertion is manifestly unreasonable and contrary to law. Moreover, EPA's assumptions about the costs of controlling Hg, which were never justified, have now been rendered virtually meaningless based on the advances achieved with low-cost halogenated sorbents.

While EPA is obligated to consider all comments submitted to the administrative record, it should be extremely skeptical of cost analyses performed by the industry to be regulated, as time and time again they have proven to be skewed toward dramatically overstating compliance costs. The assumption made by Cinergy in its power sector modeling that ACI will not be commercially available until 2010 is a case in point. This assumption is laughable, given that ACI is commercially available today. The corresponding suggestion that coal plants will temporarily have to shut down is reminiscent of the hyperbolic statements of impending doom voiced by representatives of the automotive industry when they faced emissions regulations in the 1970's. Likewise, Cinergy provides no support or justification whatsoever for the increased costs of SO_2 control, increased cost of SCR, reduced Hg co-benefits and elevated discount rate that were assumed in its modeling, compared to EPA's analysis.

Response:

For final rule modeling analysis, EPA is not incorporating other commenter assumptions into its modeling analysis. The assumptions used in EPA analysis of the final rule are discussed in EPA's IPM documentation, available in the docket. EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5492) noted that ACI technology is currently being offered for sale to utilities. For example, Council Bluffs Station is required to reduce Hg emissions by 85 percent or use an injection rate of 10 lb/mmacf. Several vendors bid on this system and offered guarantees. The commenter believes that an average 70 percent Hg reduction is achievable over a large number of boiler installations using today's technology. Based on this input, they believed that ACI technology capable of Hg reduction over a large number of installations is or will be commercially available by 2007-2008 for all coal types.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5502) referenced ACI availability and costs. Sorbent injection, either with conventional activated carbon (ACI) or chemically-treated carbon (CTC) appears to reduce Hg in the flue gas from on all coals. However, the maximum reduction achievable and the percent reduction at any given sorbent injection ratio varies with coal type. This is especially true for ACI at plants fueled with western coals. CTCs show promise in overcoming these constraints for those fuels, especially at plants equipped with a spray dryer and baghouse, but many questions remain about this new technology–sustainable and widely applicable high removals, possible emissions of the treatment chemical and/or corrosion caused by it, large quantity availability of consistent quality material, etc. ACI costs for 70 percent Hg reduction are predicted to range from 1.6 to 3.0 mills/kWh for low-sulfur eastern or Western fuels; presumably, most plants burning medium–to high-sulfur eastern fuels would have an FGD and therefore not need sorbent injection.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5429) stated that during 1999, EPA gathered data as part of the ICR program to measure Hg capture in emission control equipment designed to capture SO_2, NO_x, and particulates. These data showed that the same emission control equipment captured lower amounts of Hg at plants burning subbituminous and lignite coals. When sorbent-based Hg control technology was first applied to plants burning these Western coals, it was discovered that while 50-70 percent Hg removal was achievable for units with ESPs, there appeared to be a ceiling that prevented any higher levels of Hg removal for these coals (Durham et. al., 2002).

It was speculated that the reason for the poorer capture of Hg from Western coals was that these coals had lower concentrations of halogens such as chlorine, bromine, and fluorine. It appeared that halogens in coal resulted in gas-phase species that were critical in the reaction processes that captured Hg. During 2004, research and development was conducted to determine if higher levels of Hg removal could be achieved by supplementing halogens at these plants. Full-scale field tests were conducted in which various halogens were added to the coal, sprayed into the boiler and impregnated onto the sorbent.

During 2004, full-scale field tests were performed on plants the burn subbituminous Powder River Basin (PRB) coals and lignites. Two key configurations of emission control equipment were evaluation:

- Spray dryer followed by a fabric filter
- ESP only

The first configuration was selected because the most likely air pollution control configurations for new units burning subbituminous PRB coal or a lignite will be a spray dryer absorber (SDA) followed by a fabric filter (FF). This configuration offers cost advantages to meet stringent multi-pollutant control regulations. However, available data indicate that this configuration demonstrates particularly low, native Hg removal and the effectiveness of non-chemically treated activated carbon is limited (Sjostrom et. al. 2002).

The commenter, with support from DOE NETL and industry partners, conducted a Hg control demonstration using sorbent injection into the SDA-FF at Sunflower Electric's 360-MW Holcomb Station. Holcomb Station is located near Garden City, Kansas. The unit is a load-following sub-critical 360-MW pulverized coal opposed-fired Babcock and Wilcox Carolina type radiant boiler designed to burn PRB coal. The existing unit is equipped with three spray dry absorber modules followed by two very low air/cloth ratio reverse air fabric filters. Holcomb primarily burns two different PRB coals, Jacobs Ranch and Black Thunder.

This test program was designed to provide a full-scale evaluation of different technologies that can overcome the limited Hg removal achievable at these sites. Each technology was based on supplementing certain halogens that are not available in sufficient quantities in these coals. The program was very successful in that three different technologies were found that have the potential to produce high levels (>80 percent) of Hg removal in this difficult application (Starns, et. al., 2004b). These technologies are:

1. Coal Blending: By blending western bituminous coal with PRB coal, the Hg removal across the system increased to almost 80 percent even without injecting another sorbent. It is highly likely that firing a blend of Black Thunder and West Elk coals with ACI could result in greater than 90 percent Hg removal. Results with other coal blends must be evaluated.

2. Chemical Addition to the Coal: KNX, a proprietary chemical developed by ALSTOM Power, was found to enhance the performance of a standard activated carbon. Mercury removal of 86 percent was measured at a carbon feed rate of just 1.0 lb/MMacf.

3. Chemically Enhanced Sorbent: A proprietary product of NORIT Americas, FGD-E3, produced Hg removal in excess of 90 percent.

It should be noted that the first two approaches were tested for very short periods of time. However, the effects were verified and demonstrated the potential of these technologies. In contrast, the test program on NORIT's E-3 involved injecting the enhanced sorbent for four weeks. The results obtained during this period showed very high levels of Hg removal, average of 93 percent, at a significantly reduced injection rate of 1.2 lb/MMacf. During this test period

Hg emissions averaged 0.8 lb/TBtu.

In addition to the Holcomb tests, URS conducted a DOE/NETL sponsored program at the Great River Energy's Stanton Station Unit 10 (Machalek, et. al., 2004). This unit fires North Dakota lignite and has the identical configuration of a spray dryer/baghouse as Holcomb. During this test program two halogenated sorbents were tested, NORIT's E-3 and Sorbent Technologies B*PAC. Mercury removal levels greater than 90 percent were achieved at an injection rate of 1.5 lb/MMacf with both of these sorbents.

Following the success of the halogenated sorbents on spray dryer/fabric filters, a second round of testing was conducted on plants burning subbituminous coals that only have ESPs for emission control. This configuration represents the majority of existing plants that burn subbituminous coals and was therefore very important to the industry. Two tests were conducted during the summer and fall of 2004. The commenter conducted a test program at the Ameren Meramec Station, which burns 100 percent PRB coal, as part of a DOE/NETL sponsored program (Starns et. al., 2004c).

During this program, the performance of NORIT standard carbon Darco FOD was compared to the halogenated version Darco FOD E-3. With the standard carbon, the "ceiling effect" is observed in that a maximum removal of about 70 percent Hg removal is achieved at a feed rate of 3-5 lb/MMacf. No additional Hg removal is obtained even if the carbon feed rate is double and tripled. In contract, the E-3 overcomes this effect and greater than 90 percent Hg removal is achieved at a feed rate of 3 lb/MMacf.

A similar program was conducted by Sorbent Technologies at the Detroit Edison St. Clair Station (Nelson, et. al., 2004). This unit burns a blend of 85 percent PRB coal with 15 percent Eastern bituminous coal. This test involved the one month evaluation of Hg removal using Sorbent Technology's brominated activated carbon B*PAC injected upstream of the cold-side ESP. During the duration of the test program, B-PAC removed 94 percent of the Hg emissions when injected at a rate of 3 lb/MMacf. The Hg emission rate was reduced to 0.4 lb/TBtu.

The Department of Energy National Technology Laboratory, Southern Company, and EPRI funded a program to evaluate sorbent injection for Hg control for a year of continuous operation (Bustard et. al., 2004; Berry et. al., 2004). The test was conducted at Alabama Power Company's Plant Gaston Unit 3. The overall objective was to evaluate the long-term effects of sorbent injection on Hg capture and COHPAC® performance. Data from the testing will be used to determine:

1. Air-to-cloth ratio;
2. Advantages/disadvantages of high-permeability fabrics; and
3. Design criteria and costs for new TOXECONTM systems.

Long-Term Original Bags

Activated carbon was injected into the COHPAC baghouse nearly continuously from June 26 through November 25. Figure 6 presents a snapshot of data during the long-term test. Inlet and outlet total vapor-phase Hg, calculated Hg removal, carbon injection concentration,

baghouse cleaning frequency, and inlet mass loading are presented. Mercury removal varied between 50 and 98 percent, with an overall average of 86 percent.

One thing that was clear from these tests was that the current air-to-cloth ratio was too high to inject sufficient carbon to achieve 90 percent Hg control. A new TOXECON baghouse would have to be designed at a lower air-to-cloth ratio. One way to overcome the operating limitations at this site was to operate at low load/lower flow for an extended period. While at these conditions, carbon injection could be increased and performance data could be tracked. The primary objectives of these short tests were to 1) determine the injection concentration necessary to achieve 90 percent removal and 2) determine the impact of carbon injection on cleaning frequency at this lower air-to-cloth (A/C) ratio. An educated estimate of the ideal air-to-cloth ratio was about 6.0 ft/min.

Southern Company was able to schedule an extended period of low load operation for Gaston Unit 3. Three injection rates were evaluated during the 72-hour test. The first test was conducted at the highest injection rate possible under normal operating conditions, 20 lb/h. At this rate and the lower flow, the injection concentration was 0.9 lb/MMacf instead of 0.6 lbs/MMacf. The injection concentrations were then increased up to a maximum of nominally 3.3 lb/MMacf.

The results from this test, including inlet and outlet Hg concentrations, Hg removal, and cleaning frequency are presented in Table 1. At an injection concentration of 0.9 lb/MMacf, Hg removal was between 80 and 90 percent. When injection concentration was increased above 2 lb/MMacf, Hg removal was well above 90 percent and there were no episodes when the removal dropped below this level. Cleaning frequency was acceptable at all injection rates.

Table 1. Results Summary from Low-Load Tests, November 2003

Injection Rate (lb/h)	Injection Concentration (lbs/MMacf)	Inlet Hg Concentration (µg/Nm^3)	Outlet Hg Concentration (µg/Nm^3)	RE (%)	Cleaning Frequency (pulses/bag/hour)
20	0.9	20.6	3.2	84.2	0.6
45[a]	2.0	22.2	1.0	94.6	0.8
70	3.3	21.4	0.61	97.1	1.4

[a] Last 18 hours of 45 lb/h test.

A set (2,300 bags) of high-perm bags was purchased and installed in the B-side baghouse. The differences in design were denier (an indication of fiber diameter; 2.7 versus 7.0 denier) and permeability (nominally 30 versus 130 cfm/ft^2 @ 0.5" H_2O). The primary goals for this test were to:

1. Demonstrate improved pressure drop performance of the high-perm bags; and

2. Increase carbon injection concentration to achieve a higher Hg removal than was possible with the original bags.

Carbon injection rate was incrementally increased from 20 to 45 lb/h. Because baghouse cleaning frequency was acceptable, it was possible to inject at a constant rate and not reduce injection when inlet mass loading increased. Average Hg removal for five different injection conditions is shown in Table 2. The average Hg removal was higher in each of the shorter tests than the 85.6 percent removal that was measured for the four-month carbon injection tests with the original bags. These tests show that there is no difference in the effectiveness of carbon injection for Hg control using either the original bags or the high-perm bags.

Table 2. Average Mercury Removal, Inlet Mass Loading, and Cleaning Frequency with High Perm Bags

Injection Rate (lb/h)	Injection Concentration (lbs/MMacf)	RE (%)	Inlet Mass Loading (gr/acf)	Cleaning Frequency (pulses/bag/hour)
20	0.6	87	0.1	0.6
25	0.8	91	0.05	0.7
30	1.0	94	0.06	0.7
35	1.1	93	0.02	0.6
45[a]	1.3[a]	92[a]	0.05[a]	1.0[a]

[a] Long-term test-these data are from only the first two weeks at this condition.

Because it is expected that cleaning frequency will increase over time, especially as the new bags season, the long-term tests were conducted at an injection rate of 45 lb/h. For a two week period with an injection rate of 45 lbs/h (1.3 lb/MMacf), Hg removal was 92 percent, with a maximum hourly value of 98 percent and a minimum hourly value of 80 percent.

Conclusions from Long-Term Test

- TOXECON units designed at lower air-to-cloth ratios than COHPAC units are capable of high, 90 percent, Hg removal. For TOXECON baghouses, it is recommended that the maximum design gross air-to-cloth ratio be 6.0 ft/min.

- Activated carbon injection systems are simple, reliable, and commercially available. The control programs can be easily adapted to varying operating requirements.

- Continuous Hg measurements are challenging but possible. Advancements to the analyzers were made and the analyzers operated 24/7 for nearly 20 months.

- Activated carbon effectively reduced Hg emissions for extended periods over a wide range of operating variables with a COHPAC baghouse.

- At an average injection concentration of 0.55 lb/MMacf, over a four-month period average Hg removal was 86 percent.

- For these tests, injection concentration was limited by high, baseline COHPAC cleaning

frequency.

- High inlet loading into the COHPAC baghouse contributed to variable baseline Hg removal. It is also believed that these conditions allowed for higher Hg removal at a relatively low carbon injection concentration.

- Replacing the original 2.7 denier bags with 7 denier, high-perm bags, improved the COHPAC's ability to handle periods of high inlet loading.

- Short tests at higher injection rates with the high-perm bags showed that is was possible to achieve greater than 90 percent average Hg removal. However, Hg removal still varied between 80 and 98 percent during these periods and higher injection rates would be required to maintain consistent, 90 percent removal.

EPRI TOXECON TECHNOLOGIES

For some plants, one of the disadvantages of injecting activated carbon is its impact on the salability or reuse of ash. Tests have shown that the activated carbon interferes with chemicals used in making concrete. One straightforward, cost-effective approach to achieving high Hg removal without contaminating the fly ash is the use of the EPRI COHPAC® (COHPAC) and TOXECON™ (TOXECON) processes that are currently commercially available. COHPAC is an EPRI-patented concept that places a high air-to-cloth ratio baghouse downstream of an existing ESP to improve overall particulate collection efficiency. The process becomes TOXECON when a sorbent such as activated carbon is injected upstream of the baghouse located downstream of an ESP. With this configuration, the ash collected upstream of the carbon injection remains acceptable for sale (typically >99 percent of the ash.) The downstream baghouse provides an effective mechanism for the activated carbon to have intimate contact with vapor-phase Hg, resulting in high levels of Hg control at relatively low sorbent injection rates.

The advantages of the TOXECON configuration are:

- Sorbents are mixed with a small fraction of the ash (nominally 1 percent), which reduces the impact on ash reuse and waste disposal.

- Full-scale field tests have confirmed that fabric filters require only 10-20 percent of the sorbent required by ESPs to achieve similar removal efficiencies.

- Capital costs for COHPAC are less than other options such as replacing the ESP with a full-sized baghouse or larger ESP.

- COHPAC requires much less physical space than either a larger ESP or full-size baghouse system.

- Outage time can be significantly reduced with COHPAC systems in comparison to major ESP rebuilds/upgrades.

The TOXECON™ configuration offers an advantage over injecting carbon ahead of a single particulate control device because it prevents contaminating fly ash with carbon. Although it is a highly effective configuration for removing Hg from flue gas, retrofitting existing plants with a baghouse can be expensive. An attractive alternative solution is EPRI's TOXECON II™ technology, in which the same effect can be achieved without a baghouse but instead uses the existing multi-field ESP alone. In this configuration, carbon is injected within the ESP into downstream collecting fields. The majority of the fly ash is collected in the inlet ESP fields while carbon is injected in one or more downstream ESP fields. With this approach, most of the fly ash in the flue gas will have been collected in the first several fields (in general, 70-90 percent of the ash in flue gas is collected in each field), and beneficial use of this ash can is preserved since it will contain no carbon. The remaining fields of the ESP will then serve to collect the injected carbon. Any ESP with multiple fields can potentially use this approach. Besides activated carbon, other sorbents that can capture Hg can be used.

The main advantages of this approach are:

- preservation of the large majority of fly ash sales,
- potential for sorbent recycle, regeneration and reuse,
- enhanced oxidation of elemental Hg to increase capture in a downstream scrubber,
- minimal capital cost, and
- minimizes amount of Hg-bearing byproducts needing processing or disposal.

In August of 2004, the commenter first reported the results of the first full-scale evaluation of TOXECON II™ at Coal Creek Station through a program funded by Great River Energy and EPRI (Starns, et al. 2004a). These short-term tests demonstrated promise for Hg removals of >70 percent. Results with the mid-ESP injection of TOXECON II™ are comparable to those obtained injecting the sorbent upstream of the ESP.

The commenter stated that this technology is based on the fact that up to 90 percent in-flight capture of Hg can be achieved with a residence time of only one-half second as demonstrated on their earlier programs funded by NETL. In an ESP, the gas velocity is 4-6 feet per second, so a one-half second residence time requires 2-3 feet of space. This amount of space is often available between sections of an ESP.

It should also be noted that the data was obtained using the standard NORIT Carbon Darco FOD. In both cases the "ceiling effect" is clearly visible indicating the deficiency of gas-phase halogens. During 2005, the commenter will conduct a full-scale field test of TOXECON II™ on a plant burning 100 percent PRB coal. The halogenated sorbent E-3 will be tested at this site. If these tests confirm the performance of this advanced sorbent for this application, then higher levels of Hg removal will be achieved at greatly reduced injection rates. Keeping the sorbent injection rates low minimizes the potential of any negative effects of the carbon on the electrical components in the ESP. The combination of TOXECON II and E-3 would provide a very low cost option for plants burning Western coals that want to achieve high levels of Hg control while continuing to sell the majority of their ash.

Impact of Enhanced Sorbents on Economics of Mercury Control

The commenter stated that based upon the results of the first four full-scale field tests, cost estimates were made for applying this technology to the US fleet of coal-fired boilers. In an EPA analysis, it was concluded that 80-90 percent control of Hg for the majority of plants could be achieved for less than $2/MWh (Srivastava et. al., 2004). A DOE analysis concluded that 60-90 percent Hg removal would cost between 1.3 and 2.4 $/MWh depending on the coal and type of emission control equipment (Hoffmann and Ratafia-Brown; 2003). In addition, DOE has established goals of reducing costs over time by 25-50 percent by funding full-scale field tests of improved technology.

The test results achieved during 2004 show significant improvement in both the levels of Hg removal achievable and the cost of control technology. From four different full-scale field test programs conducted on PRB, lignite, and PRB/bituminous blends, greater than 90 percent Hg removal was achieved on the most difficult emission control equipment configurations at a cost of less than $0.6/MWhr. This shows how rapidly the sorbent-based Hg control technology is advancing.

It should also be pointed out that one of the additional advantages of the technology is that all of the users can benefit from the improvements in sorbents as they become available. The technology is sufficiently generic that the improved products can be feed using the same sorbent storage and feed equipment. This means that as additional progress is made in sorbents over the next 3 to 5 years resulting in even lower costs, the power industry will be able to take advantage of the improvements even if it purchase the equipment today. In other words, an early adopter is not stuck with 2004 technology if a decision is made today on equipment for 2008.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005). EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of second ACI option using advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis.

Comment:

One commenter (OAR-2002-0056-5535) agreed with EPA that Cinergy's assumption concerning the date of availability of ACI drives the results of this analysis, and focused our comments on this issue. EPA has already stated that it is aware of additional Hg data, particularly the testing of various halogenated sorbents. Given the success of the halogenated sorbents in capturing Hg during initial testing, it is no surprise that over extended test periods (30 days), these sorbents delivered Hg reductions higher than 90 percent at these subbituminous coal-fired boilers. Given the most recent test data and the numerous studies presented at the 2004 "Mega-Symposium" (EPA was a sponsor, so the agency is surely aware of the data

presented), the agency must concede that a national Hg reduction well in excess of 30 percent is achievable.

At issue then is the timing of the availability of such controls. EPA has received assurances from the Institute of Clean Air Companies (ICAC) that the equipment and manpower needed to design, manufacture and install the control equipment will be available to meet the requirements of a MACT standard. Industry counters with the assertions that neither the equipment nor the manpower will be available and further that the performance of the technology performance is not assured.

The commenter has explored the issue of new technology acceptance in the electric power sector and their analysis lends valuable insight into where Hg control technology is today in terms of commercialization and adoption. Basically, the development and acceptance of new technology has followed 6 steps. They are:

1. Laboratory testing,
2. Pilot-scale testing,
3. Full-scale field tests,
4. Full-scale tests at multiple sites,
5. Long-term demonstration at several sites, and
6. Widespread implementation.

Regarding the first two steps, laboratory and pilot-scale testing of Hg control technologies took place in the early to mid-90s. Full-scale field tests, including full-scale tests at multiple sites were completed during 2001-2003 as Table 1 illustrates. Table 1 lists the facilities by coal type and within each coal type in roughly chronological order. Thus, it is apparent that during the later tests, as the technology has rapidly advanced, the Hg-capture efficiency has increased to the 90 percent range across all coal types. In addition, it can be seen that the earlier tests required considerably more carbon to achieve the same results as the later tests with halogenated sorbents. The need for less carbon will considerably reduce control costs.

Table 1. Full-Scale Tests of Sorbent Injection Completed: 2001-2003

Site	Coal	Equipment	Injection Rate (lb/MMacf)	Percent Hg Capture
Brayton Point	LS-Bituminous	ESP (2)	10	94.5%
PGE	LS-Bituminous	ESP	10	90%
Cliffside	LS-Bituminous	HS-ESP	6.4	> 80%
Gaston	LS-Bituminous	HS-ESP/COHPAC	0.55	86%
Lausche	HS-Bituminous	ESP	4	70%
St. Clair	Bit./Sub. Blend	ESP	3	90%
Pleasant Prairie	Subbituminous	ESP	11.3	66%
St. Clair	Subbituminous	ESP	3	94+%

Site	Coal	Equipment	Injection Rate (lb/MMacf)	Percent Hg Capture
Holcomb	Subbituminous	SDA/FF	1.2	93%
Meramec	Subbituminous	ESP	3	90%
Stanton 10	Lignite	SDA/FF	1.5	95%
Stanton 10	Lignite	SDA/FF	1.5	90%

Source: Durham, M.D. Advances in mercury control technology to meet future needs. Presented at PowerGen, December 2, 2004. Orlando, Florida.

Step 5 entails long-term demonstrations at multiple sites. A year-long test has already been completed at the Gaston plant (average reduction 86 percent with an average performing sorbent) and 3 other month-long tests have also been completed with success at the Holcomb, St. Clair and Meramec stations. As shown in Table 2, numerous other full-scale tests at a variety of plants are either ongoing or scheduled in the 2004-2005 timeframe.

The commenter also note that state Hg rules will go into effect by 2008, which will provide additional long-term commercial experience with Hg controls. Compliance with some of the state rules begins in 2008, consequently these facilities will have installed, tested and operated ACI systems long before the compliance date. By 2008, 15 boilers in Massachusetts, Connecticut, and New Jersey will be controlling Hg by more than 90 percent. These bituminous-fired boilers have control configurations that are similar to 60 percent of the fleet and will provide the early proving ground that industry maintains is needed prior to widespread implementation of this technology.

Given this systematic evolution of the adaptation of activated carbon technology to the power sector, the commenter was confident that this technology will not just be available prior to 2010 but widely commercially available in time to facilitate compliance with a 2008 MACT standard. The commenter also noted for the record that not all plants will need to use ACI to comply with a stringent standard. Conventional controls will achieve a stringent emissions level for many plants, and precombustion controls and other technologies not represented in the IPM (e.g., oxidizing catalysts and multipollutant controls) will also be options.

Table 2. Full-Scale Tests of Sorbent Injection Ongoing and Scheduled: 2004-2005

Site	Coal	Equipment	Company
Gaston	Low-S Bit	FF	ADA-ES
Holcomb	PRB	SDA/FF	ADA-ES
Arapohoe	PRB	FF	ADA Tech
Stanton 10	ND Lignite	SDA/FF	Apogee
Yates 1	Low-S Bit	ESP/FGD	URS
Yates 2	Low-S Bit	ESP	URS
Leland Olds	ND Lignite	C- ESP	EERC

Site	Coal	Equipment	Company
Meramec	PRB	C- ESP	ADA-ES
Buck	Low-S Bit	H-ESPC-ESP	Sorbent Tech
St. Clair	PRB/Bit	C- ESP	Sorbent Tech
Miami Fort	High-S Bit	C- ESP	ADA Tech
Conesville	High-S Bit	ESP/FGD	ADA-ES
Nanticoke	PRB/Bit	ESP	ADA-ES
Arapahoe	PRB	FF	ADA Tech
Antelope Valley	ND Lignite	SDA/FF	EERC
Stanton 1	ND Lignite	C-ESP	Apogee
M.R. Young	ND Lignite	FGD	EERC
Monticello	TX Lignite	FGD	EERC

Source: Durham, M.D. Advances in mercury control technology to meet future needs. Presented at PowerGen, December 2, 2004. Orlando, Florida.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5566) submitting documentation to support its position that technology to capture Hg from power plant flue gas is readily available, effective, and affordable. Hence, the commenter urges the U.S. Environmental Protection Agency to finalize expeditiously a Maximum Achievable Control Technology standard that reflects the state of technology and the legal requirements of Section 112 of the Clean Air Act.

Recent large scale tests have been completed at several power plants nationwide that demonstrate high Hg removal is possible using sorbent injection (see attached).

> Activated carbon injection systems are simple, reliable, and commercially available. The control programs can be easily adapted to varying operating requirements. Over a four-month period average mercury removal was 86 percent. (Berry, Irvin, Monroe, et. al., 2004)

> Three different technologies [coal blending, chemical additives, and chemically enhanced sorbents] were found that have the potential to produce high levels (>80 percent) of mercury removal in [power plants that burn PRB coal). (Sjostrom, Starns, Amrhein, et. al., 2004)

Recent analysis completed by the commenter found the cost of high Hg removal to be affordable (see attached). Using EPA's cost estimates for installing sorbent injection and advanced dry scrubbers, the commenter found that 90 percent Hg control would cost an average of 0.15 and 0.22 cents/kWh, a one to three percent increase. These cost figures are in line with estimates previously published by the Institute of Clean Air Companies, which estimates a 1.2 to 3.7 percent increase, and by the Department of Energy which estimates that 60-90 percent control would cost 0.191 to 0.236 cents/kWh.

> [The commenter's] analysis found that retrofitting every coal-fired utility boiler with mercury control equipment...would cost the average household from about 70 cents to over $2.00 a month... The cost of attaining 90 percent mercury control is only slightly higher than 70-80 percent control.

Finally, to date, four states have finalized rules requiring coal-fired power plants to make significant cuts in its Hg emissions by the end of the decade (see attached). According to the Institute of Clean Air Companies, power plants already are bidding on or finalizing contracts for Hg control equipment. Over 50 plants likely will be affected by the new rules finalized by the states of Connecticut, Massachusetts, Wisconsin, and New Jersey. The pollution control market is responding to the increasing demand, making it feasible for companies to meet tight Hg limits.

The EPA has at its disposal extensive technical documentation to support a stringent MACT standard for coal-fired power plants, a standard that would achieve reductions comparable to those achieved through other MACT standards. A stringent standard with flexible compliance mechanisms can be developed to ensure that the timing and level of reductions are not compromised. The commenter urges the EPA to explore all options in fashioning a MACT rule for coal-fired power plants, and to adopt an appropriate MACT rule expeditiously.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

The commenter (OAR-2002-0056-5519) assumed that EPA would use the most recent definition of "commercially available" advocated by representatives of the electric power industry; that is, "technology that has gone through at least one year of long-term testing," one would have concluded that sorbent-based technologies (including activated carbon injection) and other combinations of technology used in series; [including selective catalytic reduction (SCR), flue gas desulfurization (FGD) and fabric filters (FF)], were currently commercially available. If EPA wold include in its determination of commercial availability all of the technologies that had already been used for at least the past 5 years by coal-fired power plants located in Europe; for example, wet electrostatic precipitators (wet-ESPs), EPA would be forced to conclude that those

technologies are not only commercially available, but also proven in practice.

The commenter was pleased to provide the following additional technical information to support these comments and responded to EPA's request on the availability and cost effectiveness of these controls:

1. "Field Test Program for Long-Term Operation of a COHP AC System for Removing Mercury from Coal-Fire Flue Gas," Report No. 41591R09, October 25,2004, (Attachment #9),

2. "Evaluation of Sorbent Injection for Mercury Control," Report No. 41986R04, October 29, 2004, (Attachment #10),

3. "Pilot Testing of Oxidation Catalysts for Enhanced Mercury Control by Wet FGD," Paper #36, Mega Symposium, (Attachment #11), and

4. Field Test Program to Develop Comprehensive Design, Operating and Cost Data for Mercury Control Systems on Non-Scrubbed Coal-Fired Boilers, Report No. 41005R19, October 25, 2004, (Attachment #12).

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5477) referenced the cost of Hg control technologies by stating that it is also important to note that both the capital costs and cost effectiveness of controlling Hg from coal-fired boilers need to be presented in a realistic manner. For example, a common but quite misleading practice is to present cost effectiveness in terms of dollars per pound of Hg removed from the application of ACI or other technologies and compare this to the costs of controlling a ton of NO_x or SO_2 from power plants. For example, typical values of cost effectiveness are as follows: $5,000 to $30,000 per pound of Hg removed for ACI; $100 to $200 per ton of SO_2 removed; and $1,000 to $1,500 per ton of NO_x removed. Obviously, the control costs appear high using such a comparison because Hg is emitted in far smaller quantities than conventional pollutants (in the U.S., power plants currently emit "only" 48 tons per year of Hg; compared to 5 million tons per year of NO_x and over 10 million tons per year of SO_2). Control costs for Hg on a pound for pound or ton for ton basis are therefore necessarily higher. However, it must be emphasized that Hg presents a far greater public health and environmental hazard on an equivalent mass basis when compared to criteria pollutants such as SO_2 and NO_x.

A more illuminating metric for estimating true costs of technology for a project is when the costs of controlling Hg with a technology such as ACI are expressed in terms of cost to the ratepayer (e.g., mills per kWh of electricity). When this approach is followed, the costs are even

lower than the costs currently being incurred for control of pollutants such as NO_x from EGUs. Note that these values for NO_x are considered cost-effective by industry and regulatory agencies, and were the basis for recent (1997-1998) state and federal requirements for wide-scale NO_x reductions from EGUs in the eastern U.S. under "Section 110 Transport SIP call" as well as the EPA's newly proposed (on January 30, 2004) Clean Air Interstate Rule (CAIR).

Response:

EPA's modeling of the final rulemaking includes presentation of results in several metrics including marginal cost and retail electricity prices. See Chapter 7 of Final CAMR RIA for further discussion of rulemaking analysis.

Comment:

The commenter,(OAR-2002-0056-5404), in response to EPA's request for comment regarding the various assumptions used for the modeling analyses conducted by EPA, CCAP, Cinergy, CATF and EEI, submitted that its analysis is based on the most accurate assumptions and therefore results in the most accurate predictions regarding compliance costs and the timing of emissions reductions expected as a result of EPA's proposed utility Hg rule. Moreover, the generic industry-wide cost projections derived from the commenter's modeling are fully supported by the more recent company-specific cost estimates completed as part of the commenter's cost recovery filings with its state utility commission. The commenter noted that other commenters modeled the effects of EPA's Hg utility rule using overly optimistic assumptions, which rendered overly optimistic conclusions regarding costs and achievability. According to the commenter, because their analysis is based on the most realistic assumptions, the commenter's analysis most accurately models the impacts of cost and timing associated with EPA's Hg utility rule.

The commenter noted that EPA recently published revised assumptions documentation used for its Integrated Planning Model (IPM) Base Case 2004 (v.2.1.9). The commenter further noted that the major changes incorporated into EPA Base Case 2004 include the capital costs of Selective Catalytic Reduction (SCR) retrofits, its gas price forecast, the number of plants available to switch to PRB coal, the cost and performance of new builds, and an update to particulate controls on existing units. However, according to the commenter, EPA has left unchanged a number of improbable assumptions that several commenters raised previously, including: the load growth rate of 1.55 percent, the cost and performance of wet Flue Gas Desulfurization (FGD) ($201/kW), the cost and performance of Activated Carbon Injection (ACI) and ACI and Fabric Filter (FF), the Hg co-benefits of FGD+SCR, the Hg emissions modification factors, and model plant aggregations amongst others. Furthermore, according to the commenter, as EPA did not mention any revision to the way coal units are aggregated, it appears EPA still plans to perform MACT policy modeling runs without the capability of modeling plant-level emission constraints. The commenter stated that this model plant aggregation change is of particular importance when analyzing Mercury MACT regulations that are implemented on a plant averaging basis. In performing its IPM modeling analysis, the commenter took particular care to represent the model plants in IPM along physical plant lines to capture the interactions that may occur between individual units at the plant level. The

commenter believed that the lack of this resolution in the EPA analysis (as well as analysis by other parties relying on the EPA version of IPM) represents a fundamental oversight in the studies performed.The commenter referred back to its Confidential Business Information (CBI) Comments filed in March 2004 as to why disaggregating coal units to the plant level allows for more realistic assessments of plant-level emission constraints.

Demand And Peak Growth

The commenter noted that the starting point for the EPA Base Case 2004 electric load growth is the projections from the reference case of AEO 2004. The commenter stated that, as in the past, EPA reduced demand growth levels in the AEO projection to account for voluntary energy efficiency programs. According to the commenter, the average annual growth rate in AEO 2004, based on the electric sales forecasts, is 1.77 percent. The commenter stated that EPA revised this growth rate down to 1.55 percent. According to the commenter, this results in a final calculated growth rate that is unchanged from the EPA Base Case 2003. The commenter stated that, as it does with air quality modeling, EPA should not include in its future energy demand modeling legislative or regulatory provisions that have not already been adopted. According to the commenter, at a minimum, EPA should use the AEO growth rates or other historically based growth rates in its reference case and, if necessary, carry out sensitivity runs with higher and lower alternative energy growth patterns that bound potential future economic growth scenarios. The commenter referred back to its CBI Comments filed in March 2004 as to why the load growth rate it uses in its analysis much more closely reflects reality.

The commenter stated that EPA's lower average demand growth rates, and the resultant energy consumption, directly impact the system and the costs of regulation. The commenter further stated that the CCAP, in a number of sensitivities based on the EPA CSA scenario, directly uses the higher average annual growth rate projected by AEO 2003. The commenter noted that other modeling results provided in the NODA utilize higher average annual growth rates. The commenter assumed a 2.3 percent annual average load growth rate and EEI assumed a 1.7 percent average annual growth rate. According to the commenter, as the annual energy growth rate is compounded over the study period, a relatively small difference in the rate has enormous implications over time.

Natural Gas Prices Have Been Revised Upwards, But Not Enough

The commenter noted that the EPA Base Case 2004 incorporates a higher natural gas forecast, with the Henry Hub wellhead price increasing, in 1999 dollars, to $3.16 in 2020 compared to $2.94 in the EPA Base Case 2003. According to the commenter, this revision of natural gas prices better represents the trajectory of natural gas prices going forward as evident in comparisons with the other natural gas forecasts utilized by EIA in its Annual Energy Outlook (AEO) 2003 and 2004, as well as in the other models submitted by the commenter and the EEI in their comments. According to the commenter, though this revision has shifted the natural gas supply curve upwards, it still falls well below the other forecasts previously mentioned. The commenter noted that AEO 2003 predicts, in 1999 dollars, a price of $3.53 in 2020 and the difference between AEO and EPA becomes slightly more pronounced with a price of $4.03 in 2020 forecasted in AEO 2004. The commenter further noted that the forecast used in their modeling is comparable to AEO with a price of $3.45 in 2020 while EEI reaches $4.13 in 2020.

The commenter referred to section II of its CBI Comments for a detailed description of how both the commenter and EPA derive their natural gas prices and how they differ. The commenter stated that gas price forecasts are important in analyses such as these as less expensive gas prices artificially alleviate the pressure on coal units to generate, and exaggerate the ease of which the system can inexpensively rely on new gas-fired generation to make up the shortfall. The commenter further stated that over the past 12 to 24 months, various federal agencies and committees have investigated the short- and long-term implications of natural gas usage and price projections. According to the commenter, EPA has not provided a comparison of its estimates to other federal findings which show significantly higher prices and decreasing domestic supply. The commenter stated that EPA's final analysis of the impact of these rules should include a range of natural gas price forecasts based on potential real world implications if EPA's overly optimistic assumptions do not come true.

The commenter has noted that historical gas prices have been volatile, but have been consistently higher then forecasts made by EPA, a trend especially evident when comparing the gas prices EPA used during the late 1990s for analyzing the impact of SIP Call regulation on the industry. The commenter noted that the table below compares recent forecasts made by EPA to historical gas prices. According to the commenter, from 2000 through 2004 these periods overlap. The commenter stated that it is worth noting that when comparing actual 2000-2004 historical data to that forecast by EPA in its 1995 and 1998 assumptions, actual prices were approximately $4.29/MMBtu, while the average of EPA's forecast over that same time period results in a price of less than $2.00/mmBtu–a difference of over 100 percent.

Higher SCR Capital Cost Assumption

The commenter stated that in the case of unit retrofit costs, especially SCR costs, the differences between EPA's estimates and the commenter's actual experience is quite substantial. The commenter stated that in the new EPA 2004 (v.2.1.9) assumptions, EPA increased its capital cost assumption of SCRs from $62/kW to $83/kW (for a representative 500 MW unit). While the commenter believed this move is in the right direction, it does not come close to reflecting the actual costs of retrofitting such devices on existing generating units. The commenter's estimates for SCR costs were developed through the knowledge and experience gained during nine SCR retrofit projects totaling 6,000 MW of capacity. The commenter stated that these actual costs for compliance with the NO_x SIP Call have been provided to their state utility regulatory commissions for review and approval. In May 2004, the commenter's regulated utility subsidiary in Indiana, PSI Energy, received approval of these same NOx pollution control retrofit costs. The commenter stated that EPA apparently has not verified its NOx control cost information by comparing it with the most recent state utility regulatory commission cost recovery filings in states which have recently implemented the NO_x SIP Call. The commenter also stated that it should be noted that the large number of SCRs retrofitted as a result of the SIP Call represents the more cost-effective (i.e., lower capital cost) units. The commenter added that EPA apparently has not considered the increasing difficulty, and thus the higher capital cost, of retrofitting increasingly smaller units as the NO_x caps get tighter. The commenter referred to costs documented and made available to EPA in their past CBI comments.

No Changes To Cost And Performance Of Wet FGD And ACI and FF

The commenter stated that with the updates included in the EPA Base Case 2004, the cost and performance of a Wet FGD and ACI and FF remain the same. According to the commenter, for a representative 500 MW unit, the capital cost of a Wet FGD is $201/kW and $55/kW for an ACI and FF. The commenter believed these capital costs continue to be significantly understated and emphasized that the cost assumptions used in its analysis, as documented and made available to EPA in the commenter's CBI Comments, Section V, more closely represent real-world retrofit cost levels that will generally be experienced by the utility industry. The commenter noted that these retrofit costs were derived from engineering estimates by the Chicago firm, Sargent & Lundy, which has extensive experience in the design and application of these technologies.

The commenter stated that while the generic industry-wide cost estimates provided in their past CBI comments indicate that EPA has significantly understated compliance costs, more recent analyses undertaken by the commenter provide further support for this conclusion. The commenter has recently started construction on a number of new wet FGD projects and has provided more refined cost estimates to the Indiana Utility Regulatory Commission (PSI Energy Cause 42622 and 42718) identifying the Company's projected costs for complying with the proposed SO_2, NO_x, and Hg reduction requirements. According to the commenter, the more highly refined commenter-specific cost estimates provided to the Indiana Commission show costs in excess of the generic cost projections previously provided to EPA in the commenter's CBI Comments. The commenter urged EPA, at a minimum, to use their more representative cost estimates for pollution control retrofits which have been previously provided.

The commenter stated that EPA did not choose to update the emission reduction factors associated with these pollution controls from those assumed in the EPA Base Case 2003 (v.2.1.6). The commenter noted that on a unit with an exiting CESP particulate control, EPA continues to assume that a Wet FGD burning bituminous coal has an emission reduction factor of 66 percent compared with 59 percent assumed by the commenter. The commenter noted that the co-benefit of a wet FGD combined with a SCR on a unit burning bituminous coal is assumed, by EPA to result in a 90 percent reduction of Hg. This is higher than the 85 percent co-benefit that the commenter believed is achievable and sustainable, and has particular significance regarding the stringency of an Hg policy that is feasible without significant additional cost. The commenter stated that this difference is found across different existing particulate controls and once again highlights EPA's more aggressive assumptions for cost and performance of retrofit options. The commenter stated that more detailed information of their experience of the actual costs of these pollution control technologies can be found in Section V of their CBI Comments. According to the commenter, while EPA moderated some of its very aggressive assumptions for emission reductions factors (ERF's) when updating from the EPA Base Case 2002 (v.2.1) to the EPA Base Case 2003 (2.1.6), the commenter believed that this issue should have been readdressed in the latest update. According to the commenter, based on recent test data, EPA acknowledges the difficulties associated with the still overly-aggressive co-benefit assumptions it assumed in its 2003 and 2004 Base Cases (v.2.1.6 and v.2.1.9), in the text of the NODA (pg. 69871), particularly regarding sub-bituminous coals. The commenter stated that, for example, for a unit configured with a coldside ESP and with a FGD and SCR, EPA recommends changing the ERF from 66 percent to 16 percent. The commenter believed that these updates should be

incorporated into any future EPA modeling as they reflect actual results at test units. The commenter also noted that these changes will have a significant impact on the Hg reduction levels that can be achieved through co-benefits, and therefore the cost of attaining Hg reductions system-wide.

The commenter stated that one clarifying point must be made regarding their assumption of ACI availability. The commenter further stated that in the EPA NODA, Section 4, part D, EPA states that for the commenter's other modeled scenarios, including a MACT scenario, it assumed ACI would be available in 2005. The commenter stated that this is factually incorrect. According to the commenter, they modeled the availability of ACI beginning in 2007 for its policy scenarios, but believed that widespread commercial availability of ACI is not likely before 2010.

Other Major Assumptions

The commenter stated that EPA recognizes the need for regular updating of model inputs to keep up with changing energy, environmental and macroeconomic markets and understanding of future conditions. The commenter further stated that, however, EPA has not taken this process to the next logical step which is an analysis of the accuracy of the models output. The commenter noted that in the case of air quality modeling the EPA has detailed guidance, Guideline for Air Quality Models, Appendix W (July 2003) 40 CFR Part 51 on the application of models and testing the models output against known actual air quality measurements and conditions.

The commenter pointed out that the true test of a model's capabilities is when its output compares favorably, within an acceptable confidence interval, to actual observed data. According to the commenter, neither in this most recent IPM modeling nor in any case prior to that has EPA ever provided information about how the IPM modeling output compares to representative known energy or environmental outcomes in the real world. The commenter stated that in this most recent reference case modeling EPA skips over the recent historical years and the current year and does not even provide any model output results until 2007. The commenter further stated that, thus, affected sources have no way of checking the reliability of the models input assumptions or output when compared against historical or recent actual energy prices, allowance prices or SO_2, NO_x or Hg emissions. The commenter added that these uncorroborated national, state or plant level emissions are the same emissions that are then used as inputs into the air quality models that EPA, and in some cases state regulatory agencies, use to evaluate in-state source impacts as well as significant contribution impacts of long range interstate transport. The commenter stated that, thus, affected sources and decision-makers have no basis for quantifying the accuracy, precision and sensitivity of the model to changes in model assumptions and ultimately in making emission control policy decisions. The commenter recommended that EPA provide an evaluation of the IPM model based on a systematic performance evaluation of a wide range of temporal and spatial outputs using current real world model inputs.

Table 1 details the major assumptions across each of the modeling described in the comments submitted by the commenter, CCAP, CATF, and EEI. The following section will lay out the implications of these assumptions on the results from these different modeling comments.

Table 1

Category	Commenter 5404	EPA (v.2.1.6)	EPA (v.2.1.9)
Source	Commenter Assumptions Document 02.03.04	EPA Assumptions Updates v.2.1.6, July 2003	EPA Assumptions Updates v.2.1.9, October 2003
Energy and Peak Demand (natl avg)	2.3% Demand Growth, 2.2% Peak Growth	1.55% Demand and Peak Growth	no changes from 2.1.6
SO_2 Control Cost and Performance	500MW = $276/kW (+adders for MACT & timing)	500MW = $201/kW	no changes from 2.1.6
Nox Control Cost and Performance (SCR)	500MW = $194/kW	500MW = $62.15/kW	500MW = $82.27/kW
SO_2 and NOX Controls for Mercury	SCR+FGD 85% Hg co-benefit (bit with CESP)	SCR+FGD average 90% Hg co-benefit (bit)	no changes from 2.1.6
Mercury Control Cost and Performance (ACI and Fabric Filter)	500MW = $95/kW	500MW - $55/kW	no changes from 2.1.6
Reference Gas Price Forecast (Henry Hub)	2005-$3.92, 2010-$3.66, 2015-$3.49, 2020-$3.54	2005-$2.89, 2010-$2.97, 2015-$2.96, 2020-$2.94	2010-$3.20, 2015-$3.25, 2020-$3.16
PRB Fuel Switching	Capital, FO&M, and VO&M PRB adders into 3 separate size categories. Additional Adders for heat rate penalty and 5 yr amortization (amortization CSA only)	$50/kW adder	increased # of plants available $50/kW adder
Capital Charge Rate (CCR) and Discount Rates (DR)	DR = 7.1%, CCR =13.6%(retrofits)	DR = 5.34%, CCR =12.0%(retrofits)	no changes from 2.1.6
Cost and Performance of New Builds	Commenter cost and performance for gas units,ICF cost and performance for coal units	Updated According to AEO 2003	Updated According to AEO 2004

Category	Commenter 5404	EPA (v.2.1.6)	EPA (v.2.1.9)
Source	Commenter Assumptions Document 02.03.04	EPA Assumptions Updates v.2.1.6, July 2003	EPA Assumptions Updates v.2.1.9, October 2003
Mercury EMF	EMF based on ICR data for all non commenter units. Commenter specified EMFs for commenter units.	Updated Attachment K. Changes made to all types, most significantly to co-benefits for SNCRs and wet FGDs.	no changes from 2.1.6
Plant Aggregation	Model plant along physical lines	Model Plant	Model Plant
Model Run Years	2004, 2006, 2007, 2008, 2009, 2011, 2015, 2020	2005, 2010, 2015, 2020	2005, 2010, 2015, 2020

Table 1 (has different headings)

Category	CCAP	CATF	EEI (CRA)
Source	EPA Assumptions v. 2.1.6, July 2003	EPA Assumptions Updates v. 2.1.6, July 2003	EEI Assumptions
Energy and Peak Demand (natl avg)	EPA Assumptions Updates v.2.1.6, July 2003, AEO 2003: 1.8% Demand and Peak Growth	1.55% Demand and Peak Growth	1.8% Demand Growth, 1.95% Peak Growth
SO_2 Control Cost and Performance (Wet FGD)	500 MW = $201/kW	500 MW = $201/kW	500 MW = $201/kW
Nox Control Cost and Performance (SCR)	500MW = $62.15/kW	500MW = $62.15/kW	500MW = $62.15/kW
SO_2 and NO_X Controls for Mercury	SCR+FGD average 90% Hg co-benefit (bit)	SCR+FGD average 90% Hg co-benefit (bit)	SCR+FGD average 85% Hg co-benefit (bit)
Mercury Control Cost and Performance (ACI and Fabric Filter)	500MW ~ $55/kW	500MW ~ $55/kW	500MW=$41.29/kW
Reference Gas Price Forecast (Henry Hub)	Various Scenarios used the following assumptions: 1) EPA (v2.1.6) 2) AEO 2003, 2005-$2.88, 2010-$3.29, 2015-$3.55, 2020-$3.69	2005-$2.89, 2010-$2.97, 2015-$2.96, 2020-$2.94	2004-$4.98, 2010-$3.33, 2015-$4.06, 2020-$4.13

Category	CCAP	CATF	EEI (CRA)
Source	EPA Assumptions v. 2.1.6, July 2003	EPA Assumptions Updates v. 2.1.6, July 2003	EEI Assumptions
PRB Fuel Switching	$50/kW adder	$50/kW adder	50% annual limit for noncurrent PRB-fired units
CCR and Discount Rates (DR)	DR = 5.34%, CCR =12.0%(retrofits)	DR = 5.34%, CCR =12.0%(retrofits)	DR = 6.05%, CCR =13.32%(retrofits)
Cost and Performance of New Builds	Updated according to AEO 2003	Updated According to AEO 2003	Updated According to AEO 2004
Mercury EMF	Updated Attachment K. Changes made to all types, most significantly to co-benefits for SNCRs and wet FGDs.	Updated Attachment K. Changes made to all types, most significantly to co-benefits for SNCRs and wet FGDs.	Hg co-benefits based on EPA's 1999 ICR data. ACI assumptions from EPRI
Plant Aggregation	Model plant	Model Plant	Unit Groups
Model Run Years	2005, 2010, 2015, 2020	2005, 2010, 2015, 2020	2004, 2008, 2010, 2012, 2015, 2018, 2020

The commenter reviewed the modeling results provided to EPA by other parties during the comment period. The commenter noted that the majority of parties filing power sector modeling results seem to agree that demand growth and natural gas price assumptions used by EPA warrant modification, and so use assumptions from other sources in their model runs. The commenter stated that it is extremely important to emphasize that in long-term planning models, such as the IPM model used by the parties to analyze the cost of new regulations, model input assumptions regarding demand growth and natural gas prices dramatically affect overall costs of regulation. The commenter stated that these assumptions should be further considered by EPA as it proceeds with its rulemaking. The commenter provided comments on some individual party modeling as indicated below.

Modeling Results Provided by CCAP

The commenter stated that CCAP produced more than a dozen runs that seem to demonstrate that timing and stringency of Hg caps have little bearing on the cost of regulation. The commenter also stated that it should be noted that the runs performed by CCAP were based on the EPA modeling runs that analyzed the proposed Clear Skies Amendments and do not specifically model the CAIR rule as proposed. The commenter stated that the results are therefore not directly comparable to any of the modeling analyses performed by EPA in the course of this rulemaking. The commenter therefore focused its comments on the conclusion that timing and stringency of Hg caps, in general, are not very significant.

The commenter stated that it would be reasonable to expect that the timing of a Hg cap would not be very significant if two things could be assumed: (1) The implementation of the

initial Hg cap coincides with any new SO_2 and NO_x regulations–so that Hg reduction benefits resulting from the installation of scrubbers and SCRs are available for complying with the Hg policy, and (2) There is sufficient time to install all compliance options (and compliance options are commercially available) before the policy takes effect. The commenter stated that, unfortunately, neither can be assumed in this case. The commenter noted that under the MACT policy that EPA proposes, Hg regulation would be introduced two years before new regulations for SO_2 and NO_x take effect. The commenter stated that this would result in unnecessary costs as coal units would need to comply with the Hg policy before controlling for SO_2 and NO_x–lessening the ability of FGD and SCR co-benefits to reduce the burden of Hg regulation. The commenter further stated that CCAP's results do not show this result because it modeled a different policy–Clear Skies–which requires new NOx controls to be in place fully two years before Hg regulations take effect (2008 vs 2010), and SO_2 controls to be in place at the same time Hg regulations take effect. According to the commenter, similarly, CCAP avoided genuine concerns over when ACI controls would become commercially available (the commenter does not expect wide availability before 2010) and how quickly the U.S. coal fleet could be outfitted with ACI, FGD, and SCR controls by assuming everything would be universally available from the beginning of the run. The commenter stated that, therefore, any claim that timing does not matter is erroneous, predicated on modeling CSA as opposed to the relevant policies, and being over-optimistic about the availability of controls.

The commenter stated that, likewise, it would be reasonable to expect that the stringency of Hg caps would not be significant if the cost of installing controls is low, the effectiveness of those controls is high, and the cost of substituting options other than coal-fired generation is modest. The commenter, however, believed the cost of retrofits to be much greater than the estimates of CCAP, which used EPA assumptions, especially for the smaller units that would become the price-setting units as the caps were made more stringent. The commenter also believed Hg EMFs to be larger (i.e., the reductions smaller), and the cost of natural gas to be greater–which both increases the need, and the cost, of switching from coal-fired generation to meet more stringent caps. It is the commenter's belief that more stringent caps would not be possible without greatly increasing the cost burden of Hg regulation.

Modeling Results Provided By CATF

The commenter noted that the Clean Air Task Force ("CATF") performed two runs using EPA assumptions. The commenter stated that the first run shows CAMR MACT plus CAIR using EPA assumptions, which allows for a relatively direct comparison with the commenter's model results for CAMR MACT plus CAIR. According to the commenter, from this comparison, it is clear that EPA assumptions allow more pollution controls to be installed at lower costs than the commenter's assumptions allow–reducing the cost of regulation.

The commenter stated that the second run provided by CATF shows that EPA assumptions allow for a much more stringent MACT rate while significantly increasing regulatory costs by about 30 percent. The commenter further stated that this result is predicated on FGD and SCR combinations providing the 90 percent reduction needed for the stringent MACT for both bituminous and sub-bituminous coal units. The commenter maintained that it is unlikely that an FGD and SCR combination could be depended on to meet such a strict standard, particularly for units burning sub-bituminous coal.

Modeling Results Provided By EEI

The commenter stated that EEI runs adopt the industry's view on FGD and SCR co-benefits and other Hg emission factors, and therefore show higher annual Hg emissions under MACT policies than EPA assumptions produce. The commenter added that, in fact, EEI's forecast for emission levels are very similar to the emission levels shown in the commenter's filing. The commenter further added that even so, it could be said EEI's runs do not go far enough. The commenter believed EEI's assumptions for costs of emission control equipment were comparable to EPA's cost estimates. The commenter states that while energy demand growth assumptions were marginally increased from EPA's starting point, the growth rate is still fully one-third below historical growth and far below what is likely to occur over the forecast period. The commenter further states that these assumptions serve to significantly reduce EEI's estimates of regulatory costs.

The commenter stated that, in sum, there are significant issues with the assumptions used by the other commenters in their modeling analyses, resulting in overly optimistic projections regarding control costs and achievability of reductions. Based on the foregoing, the commenter submitted that its assumptions are the most realistic and that its modeling, therefore, most accurately predicts the costs of the proposed rule as well as the achievability of the proposed timing. The commenter stated that EPA's final rule should include a series of analyses that factor in assumptions comparable to the commenter's assumptions.

Response:

EPA appreciates the commenters suggestions. A complete discussion of EPA's modeling of costs and energy impacts can be found in Chapter 7 of the Regulatory Impact Analysis. EPA also appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

The commenter (OAR-2002-0056-5460) stated that ample evidence suggests that Activated Carbon Injection (ACI) and other Hg control options are already commercially available. See Document ID No. OAR-2002-0056-3454 (Institute of Clean Air Companies Comments); and No. OAR 2002-0056-2888 (NESCAUM Comments). The commenter stated that given the evidence of commercial availability, EPA has not adequately explained its conclusion that ACI will not be available for commercial application until after 2010.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5548) stated that ACI or a similar Hg-specific control technology will be necessary to meet any of the lower caps (i.e., beyond co-benefit reductions) under consideration (e.g., EEl's 2015 cap or EPA's 2018 cap). However, many commenters have advocated that the allowance allocation adjustment factors for EPA's proposed Phase I 2010 cap (or allowance adjustment factors proposed by others) continue on into later stages of the Hg program. Cinergy has stated that such allocation preferences should end with any cap beginning in 2015. The commenter agrees with Cinergy's position on this issue.

Response:

The final rule takes into account the different levels of mercury control that lignite, bituminous, and subbituminous coals can achieve using existing NOx and SO_2 controls and uses coal adjustment factors for determining the state emission budgets and determining unit-level allocation under EPA's example allocation methodology for States. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Indian Country Emissions Budgets, EPA, March 2005.

Comment:

One commenter (OAR-2002-0056-5548) stated that ACI will be available for initial application by 2010 and for widespread commercial application by 2012-2015. EPA has staked its decision to lower the cap beyond co-benefits on its expectation that "ACI technology would be available for commercial application after 2010 and that removal levels in the 70 percent to 90 percent range could be achievable." It is noteworthy that all of the modeling that EPA highlights in the NODA assumes some availability of ACI by 2010. In a July 20, 2004 report to EPA by DOE officials responsible for development of Hg-specific control technologies such as ACI, DOE concluded "ACI works," but needs further demonstration, now underway, to be commercially available by 2010-2012. Hence, there is little question about the technology becoming available for all coal ranks.

The commenter believed that the issue of levels of control with ACI among coal ranks must be addressed. DOE reports that its near term goals remain to demonstrate 50-70 percent reduction on bituminous coals by 2005 and on lower ranks coals by 2007.6 Thus, DOE's near term goals do not show any variation by coal rank, and the later demonstration date of 2007 for lower rank coals is irrelevant for post 2014 application. To date, there is no basis to believe that DOE will not achieve its stated goals. As referenced in the NODA, early pilot testing of a COHPAC system on a bituminous unit (Gaston) showed longer-term testing removals of 78 percent, and ACI (not COHPAC) testing at a subbituminous coal-fired unit (Pleasant Prairie) showed longer-term testing removals in the range of 60-70 percent. Testing at two other bituminous plants (Salem Harbor and Brayton Point) showed longer-term removals at higher levels, although there are some concerns about whether either of these units is sufficiently representative for replication.

In its July report to EPA, DOE further states that its longer-term goal is to demonstrate emission reductions of 90 percent by 2010. However, in the July presentation, its current projection ("DOE estimate for performance potential with ACI") for ACI/COHPAC is 80 percent removal for a CS-ESP bituminous unit, 70 percent removal for CS-ESP and CS-ESP/FGD-Dry subbituminous units, and 70 percent removal for all lignite units (except that HS-ESP/FGD lignite units increase to 83 percent). It is these DOE projections upon which EPA is basing its proposed decision to implement a cap significantly lower than co-benefits.

Based upon this information, the commenter believed that EPA must evaluate the equities of allowance allocation adjustments among coal ranks for post co-benefits caps. The first risk to evaluate is technology/compliance risk. There is a risk that the as yet unproven technologies upon which DOE relies will not work well, or will not work well at the levels predicted. However, this risk is generally equal among all coal ranks. The DOE currently has 41 field tests underway which will be completed by 2007. Of these 41 tests, 27 involve subbituminous or lignite coals. These extensive tests, the majority of which concentrate on low-rank coals, indicate that DOE will be able to achieve its stated removal targets within the given timeframes. However, no coal rank has any more of guarantee that this will in fact come to pass than any other.

The commenter added that there has been short-term testing is true for all coal ranks, and the fact that there might be a few more short-term field tests for bituminous coal would seem to make little overall difference in technology/compliance risk because there has been no substantial testing beyond short-term field tests for any coal rank. Hence, the technology risks associated with DOE meeting its stated control technology goals remain equal among coal ranks.

The commenter also noted that there is no greater compliance risk for any coal rank because each coal rank has an available "backstop" technology that will allow it to comply. Bituminous units can install FGD to reach 60 percent removals, and subbituminous units can install FF to reach 65 percent removal (CRA 2004 EMFs). The commenter did not believe there is any plausible basis to mandate these control technologies now solely for Hg removal, as EPA has concluded, when developing Hg-specific control technologies show such promise and greater cost-effectiveness. However, that conclusion becomes less appropriate for any post-cobenefits caps. In the event that technology risk impacts one coal rank but not another in the compliance year, either coal rank has an available backstop compliance option, and therefore compliance risk remains equal among coal ranks for the later caps and cannot justify application of any allowance allocation factors (the fact that the backstop technology for either coal rank may cost more than an ACI-based alternative is not a relevant basis to adjust allocations because both subbituminous and bituminous coal users share equal technology development risk ACI, and their backstop technologies are both within the same range of cost-effectiveness) .

Based on the above information, the commenter believed that EPA clearly cannot support an allocation adjustment ratio whereby bituminous coal is assigned a factor of 1 and lower ranks coals are assigned higher factors for post co-benefits caps because that approach assumes that bituminous coals have no technology compliance risk, and that lower rank coals have greater technology/compliance risk, which is simply not true. As well, an allocation ratio of 1.25 for subbituminous and 3 for lignite, and seemingly derived for a co-benefits approach, bears no relationship to whatever differing levels of risk might be perceived among the coal ranks for

Hg-specific control technologies that have not been commercially deployed (the control differences are nominal (10 percent) and do not warrant those allocation ratios). Thus, there is nothing that is either "directionally correct" or "equitable" in awarding extra allowances to low rank coals that bears any relationship to the technical and compliance risks among coal ranks for post co-benefits caps.

Response:

EPA appreciates the commenters input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005). EPA's IPM modeling assumption for ACI are based on EPA's Office of Research and Development (ORD) assessment. Although modeled in IPM to be available immediately for all coal-fired generation as a simplification of modeling, ORD assessment concluded that ACI could not be fully deployed on all plants by 2010 timeframe.

The final rule takes into account the different levels of mercury control that lignite, bituminous, and subbituminous coals can achieve using existing NOx and SO_2 controls and uses coal adjustment factors for determining the state emission budgets and determining unit-level allocation under EPA's example allocation methodology for States. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Indian Country Emissions Budgets, EPA, March 2005.

Comment:

One commenter (OAR-2002-0056-5548) noted that there is a 10 percent difference between DOE's removal targets for ACI applied to bituminous coal (80 percent) and the lower rank coals (70 percent) (all ranks share an equal risk that these levels will not be achieved in practice). The difference between these controls levels is both small (10 percent) and equal to or above the nominal required reduction (an aggregate 70 percent reduction in Hg for EPA's 15-ton cap). The commenter was not aware of any compelling reason to subsidize low rank coal users that may have nominally different control costs. Nor is the commenter aware of any compelling reason for EPA to require bituminous coal users to provide that subsidy (in the form of lost allowances due to allocation ratios) to users of the other coal ranks.

The commenter was not aware of any policies or reasons supporting such subsidy because they appear not to have happened under similar circumstances. Thus, the commenter is not aware that EPA considered subsidizing bituminous coal under the CAIR because it would cost users of that coal rank significantly more to meet SO_2 caps than users of subbituminous coal. Nor is the commenter aware that EPA considered granting bituminous coal users extra SO_2 allowances under CAIR to help prevent such users from switching to subbituminous coals to meet their SO_2 requirements.

For similar reasons, the commenter found no plausible, equitable basis for awarding such subsidies here. If the market finds it more difficult or expensive to control Hg emissions from

lower rank coals than from bituminous coals it will decide whether to buy allowances to cover that shortfall, or it will switch coals, which is how it resolved control issues under Title IV (Acid Rain) of the Clean Air Act Amendments of 1990, how it will resolve control issues under CAIR, and how it should resolve control issues under the Hg rule.

It is also important to note that a 70 percent Hg reduction for subbituminous coal results in essentially the same emissions as an 80 percent reduction on bituminous coal. The mean Hg content in subbituminous coal is 5.74 lb/TBtu, and the mean Hg content for bituminous coal is 8.59 lb/TBtu. If Hg emissions from each coal are reduced by 70 percent and 80 percent respectively, the resulting Hg emissions are 1.722 lb/TBtu for subbituminous and 1.718 lb/TBtu for bituminous coal, or no difference at all. In fact, on a risk basis, the less homogeneous nature of bituminous coals means that these equal aggregate numbers underestimate the greater reduction risk associated with bituminous coals.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. The final rule takes into account the different levels of mercury control that lignite, bituminous, and subbituminous coals can achieve using existing NOx and SO_2 controls and uses coal adjustment factors for determining the state emission budgets and determining unit-level allocation under EPA's example allocation methodology for States. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Indian Country Emissions Budgets, EPA, March 2005.

Comment:

One commenter (OAR-2002-0056-5548) noted that, in the NODA, EPA presented the results of a number of attempts to model the impact and costs of various proposed Hg rules. The significant divergence in the modeling results, even for ostensibly similar regulatory scenarios, demonstrates the fundamental problem in devising this rule given the high degree of uncertainty in the model inputs and assumptions. It argues strongly in favor of the commenter's original recommendation, to defer setting a hard cap until adequate information is available about the performance and cost of co-benefit and Hg-specific control technologies.

First, the commenter did not believe that EPA's, EEI's or Cinergy's model inputs are quite right, although each has developed appropriate inputs for individual components. The commenter also did not believe that EEI's model is correct because it has apparently assigned little or no cost to switching to subbituminous coal for SO_2 compliance, while both EPA and Cinergy have assigned costs to that action. This would tend to underestimate the level of FGD installation needed for compliance with the CAIR, and therefore underestimate co-benefits. Hence, the commenter believes that either EPA's or Cinergy's inputs on the cost for coal switching should be used, and generally believes that Cinergy's formula presents a more comprehensive approach, although there may be little difference in results between Cinergy's or EPA's inputs.

Next, the commenter believed that EPA has significantly underestimated the cost of control equipment. This would tend to overestimate the number of FGD units that would be installed to meet the CAIR, and hence overestimate co-benefits. The commenter also believed that either EEI's numbers or Cinergy's pollution control cost numbers better reflect current reality. These two variables, plus the EMF factors, are what will most influence the final estimate of co-benefits reductions, cost and performance. The commenter had no comment on growth numbers.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. See comment response above for EPA's response to commenter's criticism of EPA modeling. EPA agrees with the commenter that modeling that shows costs for coal switiching is a better representation of costs.

Comment:

One commenter (OAR-2002-0056-5497) stated that in order to respond to this question, it is important to define what is meant by "availability." Four stages of development must be recognized in this context: (1) tests, (2) demonstrations, (3) commercially available at individual units, and (4) commercially available for the entire utility system. For a nationwide rulemaking that imposes controls on the entire population of coal-fired boilers in this nation, commercial availability for the entire system of boilers in this nation is the most important issue.

A test is a short-term evaluation of Hg removal as a function of different variables, such as injection rate of activated carbon, flue gas temperature, etc. and may gather information for a few hours to up to 30 days. A test might identify obvious balance-of-plant impacts, but not subtle impacts that will require more operating time. In the context of the ACI work completed to date, the commenter considered all field work with ACI/ESP to be tests. A demonstration requires one to two years of operation, including an assessment of impacts on the plant that require the accumulation of significant operating hours. Commercial availability at a unit scale is where a utility can purchase an individual or limited number of processes, and receive credible performance guarantees. Also, unit scale Hg controls may only be commercially available for certain boiler types, unit configurations, or fuel types. The purchaser can access an experience base assuring risks to operation are commensurate with other aspects of plant operation (e.g., the process does not risk operations any more than usual activities). Finally, commercial availability at the system scale requires both commercial availability at the unit scale, and the necessary infrastructure to provide reagents, construction material and manpower, and transport of key process requirements for the entire population of boilers. System availability is the ultimate goal that must be achieved to enable broad utilization of a technology.

The commenter had provided an estimate of the availability of ACI technology for each of these four stages of development. The earliest that any technology will be available on a system basis is 2011 and for some configurations of coal type, control technology and Hg reduction level availability on a system basis will not be achieved until 2014.

Finally, the utility industry has had many experiences that have demonstrated why several years of demonstration effort are required before a new control technology should be applied broadly. For example, hot-side ESPs were deployed without sufficient experience and resulted in many unanticipated problems. In the mid-1970s, the first hot-side ESP applications on boilers firing western low sulfur coal found persistent particulate matter removal shortfalls, in contrast to performance predictions and guarantees offered by suppliers. Research was initiated in the early 1980s to provided an explanation of this behavior, which resulted in a solution five years after the problem was first identified and long after these ESPs were in commercial service.

This experience is significant for ACI, especially in applications at units with smaller ESPS. Carbon particles or fly ash co-mingled with carbon may quickly accept–and then ultimately lose–the electrostatic charge so that a certain fraction of carbon injected could be released from the plate before rapping, to be either re-entrained or to disturb the quiescent zone within the collection hopper. This complication has not been observed with ACI demonstrations to date for two reasons. First, the ESP units employed in the demonstration tests exhibit relatively generous specific collecting area so that any carbon material that eludes collection in the first few fields is ultimately collected in later fields. Second, the duration of tests has been limited. It is not clear how long it will take to establish steady-state conditions within the collected ash layer. As demonstrated with the hot-side ESP experience, steady state conditions with respect to electrical properties of the entire layer of ash must be established, not simply the outer layer adjacent to the flue gas.

The commenter suggested for these reasons, it would be imprudent to require the deployment of insufficiently demonstrated technologies to the entire population of coal-fired utility boilers and to potentially jeopardize the reliability of the electricity supply in this nation.

Response:

EPA appreciates the commenter's input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

5. EEI estimated that ACI would be less expensive per pound of Hg removed than EPA estimated. Cinergy assumed higher capital costs for ACI than EPA. Are EPA's Hg control cost assumptions reasonable? EPA is seeking additional detailed data addressing the validity of the cost assumptions for ACI.

Comment:

One commenter (OAR-2002-0056-5475) noted that highly effective Hg control technologies are available and cost effective. Two companies that supply bromated activated carbon injection (B-ACI) for utility power plants offer removal rate guarantees. The ACI industry reports that there is a sufficient supply of activated carbon to supply the anticipated demand for Hg control by the regulated industry. More than 800,000 tons of activated carbon are currently produced worldwide annually. The technology has proven to be more cost

effective than initially thought by EPA. The cost of ACI has been reported to be ranging between $2,000 and $20,000 per pound of Hg removed, much less than the control cost of $50,000/lb that was considered in the proposed rule. The B-ACI technique has reduced the amount of activated carbon necessary to create the same effect. By reducing the amount of activated carbon needed the B-ACI technology will have a significant impact on the results of IPM modeling included in the proposed rule. This commenter stated that the impact from the use of B-ACI will serve to positively enhance the economic viability of Hg control under MACT. It would also address any potential concerns regarding sufficient availability of activated carbon.

Response:

EPA appreciates the commenter's input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5510) stated that EPA should analyze supply and price response to demand created by the various ACI scenarios. The current supply of activated carbon is not sufficient to accommodate a substantial demand from the utility sector and it could take up to five years to bring activated carbon production facilities on line.

Response:

Given that the first phase cap is set at the Hg co-benefits of CAIR, EPA does not project significant amount of ACI to be retrofitted until the 2018 timeframe. With regard to demand for activated carbon, EPA notes that markets respond to the demand for materials, much like under the NOx SIP call supply for catalyst increased with demand. See Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA, October 2002, in docket.

Comment:

One commenter (OAR-2002-0056-5488) stated that halogen-impregnated sorbents have been shown to dramatically improve the effectiveness of sorbent injection systems, particularly for sub-bituminous and lignite coals. These systems are also commercially available, as evidenced by the fact that construction of the subbituminous coal-fired unit 4 of MidAmerican Energy's Council Bluffs power plant is moving forward under a permit that relies on their use or use of an equivalently effective control method. This unit was permitted with the condition that it achieve a high degree of Hg reduction, which was deemed achievable based on test results obtained for lignite coal with iodine-impregnated carbon.

The combination of sub-bituminous coal with a spray dryer for SO_2 removal has been viewed as a challenging configuration for Hg control, because the spray dryer is thought to remove halogens that are needed to enhance Hg capture from the flue gases. However, in recent

tests at Sunflower Electric's Holcomb Station, 77 percent Hg removal was achieved through injection of a proprietary halogen-treated sorbent offered by NORIT Americas, at a very low injection rate of just 0.7 lb/MMacf. The cost of the sorbent was just $0.65/lb, making it much more cost effective than either iodine-impregnated carbon or injection of untreated activated carbon (at higher injection rates). Of note, rates of Hg capture at the Holcomb Station were also boosted significantly simply by blending the sub-bituminous coal with a western bituminous coal that had higher chlorine content.

Recent test results achieved with brominated powdered activated carbon (B*PAC) are also impressive. B*PAC has been tested at seven different power plants, including four full-scale tests. Mercury removal rates ranged from 70-98 percent across a wide variety of coals and configurations. Researchers at DOE and Sorbent Technologies Corp. have estimated from these tests that with B*PAC costing about $0.75/lb, Hg removal costs may be just 10-20 percent of DOE's baseline estimates.

Full-scale tests with B*PAC have recently been conducted at Detroit Edison's St. Clair Power Plant, which typically burns 85 percent sub-bituminous coal blended with 15 percent bituminous coal and is equipped with a cold-side ESP. Mercury speciation upstream of the sorbent injection point is estimated to be 80-90 percent elemental Hg. Nevertheless, Hg removal rates of 90 percent or higher were achieved with B*PAC injection rates of just 3 lb/MMacf, with no additional control equipment required. The B*PAC vendor estimates that with cold-side ESP, 90 percent removal can be achieved at a cost of less than $9000 of sorbent per pound of Hg removed. Moreover, because B*PAC injection rates are so low, its use has negligible impact on characteristics of fly ash for use in cement.

Environmental Defense and Western Resource Advocates have produced a white paper entitled Mercury Air Pollution: The Case for Rigorous MACT Standards for Subbituminous Coal, which shows that there is no technical justification for a separate subcategory of Hg MACT standards for plants burning subbituminous coal. A copy of this paper was attached to our June 29, 2004, comments and is incorporated by reference herein. Although produced more than a year ago, that paper found that 90 percent Hg reduction is achievable at effectively the same costs irrespective of whether a plant burns bituminous or subbituminous coal or a blend of the two (as is common practice), using activated carbon injection and either a fabric filter or an ESP with a compact baghouse for particulate collection.

Since that paper was issued in May 2003, many advances have been made in Hg control technologies. These technological advances, such as using halogenated sorbents in a sorbent injection system, advanced dry FGD, ECO technology, or even simply blending some higher chlorine bituminous coal at subbituminous or lignite fired power plants, are discussed in detail above. The pilot and full scale tests of these technological improvements continue to prove that high levels of Hg control can be cost effectively achieved at all coal- fired power plants, regardless of the type of coal burned.

As mentioned above, the Iowa Department of Natural Resources(IDNR) recently imposed an emissions limit reflecting 83 percent reduction in Hg as MACT for a new unit burning subbituminous coal at MidAmerican Energy's Council Bluffs power plant. In doing so, the IDNR relied on results from a full-scale test of activated carbon injection for Hg control at

Great River Energy's Stanton Generating Station, which burns North Dakota lignite coal. Tests at Stanton found that on average 81 percent Hg removal could be obtained with the use of activated carbon and a spray dryer/baghouse combination. Moreover, with the use of iodine-impregnated activated carbon, 97 percent Hg removal efficiency could be achieved. The IDNR determined that the subbituminous coal to be burned at the Council Bluffs plant was similar to lignite coal in terms of Hg emissions, and thus relied on the Stanton test to justify the MidAmerican permit limits. Subsequent tests at Stanton with B*PAC injection and the spray/dryer baghouse combination have demonstrated nearly 90 percent removal with only 1 lb/MMacf sorbent injection, at an estimated cost of only $2500 per pound of Hg removed. These tests demonstrate that the Stanton facility, burning lignite coal, could easily and cost-effectively meet an emissions limit of 1 lb/TBtu, almost a factor of 10 lower than EPA's proposed MACT for existing lignite facilities.

EPA's proposal to set disparate standards depending on rank of coal is thus unjustified and lacking in any reasoned basis. Moreover, the approach unfairly subjects those who live near power plants burning lower rank coal to much higher levels of Hg emissions. EPA must take into account recent information that shows technology is currently available to achieve high levels of Hg control on a cost-effective basis regardless of the rank of coal to be burned and use this information to set uniform, protective standards.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. The final rule takes into account the different levels of mercury control that lignite, bituminous, and subbituminous coals can achieve using existing NOx and SO_2 controls and uses coal adjustment factors for determining the state emission budgets and determining unit-level allocation under EPA's example allocation methodology for States. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Indian Country Emissions Budgets, EPA, March 2005.

EPA appreciates the commenter's input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter's (OAR-2002-0056-5492) question: "EPA is seeking additional detailed data addressing the validity of the costs assumed for ACI."

The response to this question is divided into two parts: activated carbon availability and development of new sorbents.

Activated carbon availability: If the activated carbon industry converted to a 24/7 production scenario, then the productivity would conservatively lead to about 60,000 tpy of excess carbon available in the U.S. Assuming a 15 lb/MMcfm activated carbon injection rate

used in conjunction with CS-ESP, the excess activated carbon production capacity could be used to control Hg emissions from about 6 GWe generating capacity. If one assumed that all units that were retrofitted with ACI also installed fabric filters, then the assumed injection rate would be lowered to about 1 lb/MMcfm and about 105 GWe of capacity could be controlled using activated carbon. Since EPA modeling suggests that about 2 GWe of ACI capacity will be required in 2015, the cost for commercially available activated carbon between now and 2010 should not be driven upward due to demand vs. supply constraints.

Other models project higher ACI installed capacity. In the Notice, EPA cited model results that projected 13 to 17 GWe of installed ACI capacity for cap and trade scenarios for 2010 annual Hg emissions between 25-34 tpy. For various MACT approaches, the installed ACI capacity was between 15 and 120 GWe. The worldwide excess production capacity is estimated to be 150,000 tpy of activated carbon. Depending on the injection rate, this would limit the installed ACI capacity to 15-22 GWe. Regulations which require more than 22 GWe of ACI capacity would cause a supply-demand constraint and cause the price of activated carbon to increase in response to the demand. The activated carbon supply vs. the 2010 installed ACI capacity must be carefully studied.

Development of new sorbents; The activated carbon sorbent is the largest Hg control annual cost component. There have been numerous tests of brominated activated carbons on Powder River Basin and lignite coals. In those tests, significantly improved performance has been recorded. During a four week test program at the subbituminous coal fired, 360 MWe Sunflower Electric Holcomb Station, Hg removal increased from a baseline of less than 20 percent to over 90 percent for the entire period at injection rates less than 1 lb/MMcfm. The projected cost of the sorbent is a factor of two higher than conventional activated carbons, but the usage rate is a factor of seven to ten less. This will result in a significant decrease in annual operating cost.

There is potential for activated carbon injection technology to reduce costs significantly, by a factor of 3 to 7 between now and 2010. Utilities can take advantage of improved carbon performance since they can change their carbon specifications after the equipment is installed.

Response:

Given that the first phase cap is set at the Hg co-benefits of CAIR, EPA does not project significant amount of ACI to be retrofitted until the 2018 timeframe. With regard to demand for activated carbon, EPA notes that markets respond to the demand for materials, much like under the NOx SIP call supply for catalyst increased with demand. See Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA, October 2002, in docket.

Comment:

One commenter (OAR-2002-0056-5571) stated that while the technology vendors participate in conferences and announce the viability of control technologies (mostly Activated Carbon Injection) for ~200 MW units, there have been known and guaranteed controls at <200 MW units. Worse, virtually no vendors have focused on <100 MW units. This commenter fully

supported the comments submitted by UARG and the study conducted by Charles Rivers Associates (CRA) on the inadequacy of a three-year period for complying with EPA's MACT limits. EPA has the discretionary authority to extend the compliance deadline by a year. This commenter believes that EPA should use its discretionary authority under § 112(i)(3)(B) and extend the deadline by a year for all units, and it should assist public power utility units needing even more time in obtaining presidential extensions on a case-by-case basis.

The process of funding and installing a major retrofit is different for small public power systems than for larger investor-owned systems. Public power units must normally obtain financing through publicly approved bonds. This is not a process that moves quickly, nor is it one with a guarantee of success. Once the funding approval process is completed, these small units most then compete with large, privately held units to obtain services from vendors of emission control equipment and to procure skilled labor to install that equipment. An equipment vendor is far more likely to be responsive to a large utility (often an investor utility) seeking a number of multi-million dollar retrofits than to a small public system with an environmental compliance staff of one or two Full-time Equivalents (FTEs) and a limited compliance budget.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. Given that EPA is finalizing a cap-and-trade approach, the program would not necessarily require the installation of coantrols on units less than 100 MW.

Comment:

The commenter (OAR-2002-0056-5404) stated that currently, most power plants market some of their fly ash for use in ready-mix concrete and other beneficial applications. The commenter added that some plants with scrubbers market gypsum produced in the wet flue gas desulfurization (FGD) process for use in wallboard fabrication.

The commenter noted that as explained in their June 24 comments and the comments of others, installation of an activated carbon injection system to control Hg emissions would cause elevated carbon levels to prevent these beneficial uses of power plant fly ash. The commenter stated that activated carbon that has the greatest capture efficiency is in the 4-8 micron range. The commenter added that most of this activated carbon will be captured by the plant's ESP or fabric filter, and thus will be present in the fly ash. The commenter further added that testing experience has shown that, because of the small size of these carbon particles, some of the activated carbon is carried through into the scrubber system. The commenter stated that the presence of carbon in either fly ash or the gypsum produced by wet scrubbers is highly problematic to beneficial reuse.

The commenter stated that fly ash can be utilized as a substitute for cement in ready-mix concrete–but to do so, it needs to comply with ASTM-C618, which specifies the maximum acceptable carbon content for concrete filler applications. The commenter added that it is necessary to limit carbon content in concrete because carbon reduces the strength of the concrete and causes premature failure. The commenter noted that this result occurs because carbon

inhibits air entrainment in the concrete. The commenter stated that air increases the strength of concrete and reduces the permeability of the concrete. (The commenter noted that fly ash reduces the amount of Portland cement that needs to be used in the concrete.) According to the commenter, state transportation departments typically tighten the maximum allowable carbon content as compared to the ASTM standard. The commenter notes that the ASTM standard for carbon content of concrete filler, as well as two state DOT specifications, are shown in Table 2 below.

The commenter notes that gypsum produced in wet flue gas desulfurization (scrubber) processes is used in construction materials and wallboard. The commenter also notes that a portion of the gypsum is also used to produce spackling or "mud" for wallboard installation. The commenter further notes that for cosmetic reasons, gypsum needs to be high purity and white in color. The commenter added that, however, even very small levels of carbon in wallboard will cause the paper to peel, making the wallboard unusable. The commenter stated that, accordingly, to be usable, the gypsum material quality needs to be high with very small amounts of carbon. The commenter noted that gypsum specifications for wallboard use also are set forth in the table below. The commenter pointed out that, as noted above, however, because of the small size of the ACI carbon particles, some carbon will inevitably bleed through to the scrubber, resulting in gypsum product degradation (and, as discussed in the commenter's June 24 comments, potential catastrophic scrubber foaming issues).

Table 2. Carbon Content Specifications for Product Streams

	Concrete/Construction	**Pennsylvania Department of Transportation**	**Texas Department of Transportation**	**Wallboard**
Ash	ASTM-C618 <6 percent	ASTM-C618 and <4 percent	ASTM-C618 and <3 percent	NA
Gypsum	*	NA	NA	*

*gypsum specification is ≥92 percent CaSO4 and ≤ 2 percent total inerts. Inerts include a combination of ash, limestone minerals and carbon.

The commenter stated that recently, some representatives of the control technology industry have claimed that the problem of increased carbon levels in fly ash and scrubber gypsum has been "solved." The commenter stated that, for example, one company has been aggressively marketing a brominated activated carbon technology. According to the commenter, they claim that, because the bromination results in less carbon being needed to achieve Hg removal, there is no issue of increased carbon levels in fly ash with this technology. The commenter stated that these assertions are, to date, unproven.

The commenter stated that this company has not claimed that anything in its process eliminates increased carbon levels in fly ash; it simply reduces the total amount of carbon used in the injection process. The commenter further stated that, however, carbon levels may still exceed ASTM or State standards (or the specifications of the companies that are accepting the fly ash)–and may still be high enough to lower the structural stability of the concrete. The commenter stated that this is particularly the case because the DTE St. Clair plant on which the

company's ACI was tested included an inordinately large ESP, one of the largest in the industry. The commenter stated that, indeed, this ESP was 700 SCA, as compared to much smaller ESP with an average size of 200-250 SCA for the rest of the industry. According to the commenter, as a result, the St. Clair plant was able to achieve a higher removal efficiency with a lower level of carbon injections than would be expected from most power plants, raising further concerns about the actual levels of carbon that would be present in the fly ash. The commenter stated that, in addition, the tests at St. Clair were of very short duration and are not of sufficient length to be considered "commercial operation."

The commenter stated that even if the ash meets ASTM specifications, does not impact the structural stability of concrete and would otherwise be acceptable to concrete manufacturers, the levels of carbon present in the ash would discolor the concrete–and thus almost certainly render it unacceptable to most concrete manufacturers. The commenter added that, similarly, as noted above, even trace amounts of carbon (which certainly would be expected even from the smaller amounts of brominated ACI proposed by the company) would render scrubber waste unusable as gypsum. The commenter stated that, thus, even if the carbon issue could be solved with respect to fly ash, it would not be solved with respect to scrubber gypsum.

The commenter stated that, in sum, the control technology industry has not yet come close to proving that the issue of increased carbon levels in fly ash is solved. The commenter added that yet a single power plant can generate thousands of tons of fly ash and gypsum per day, and if those wastes cannot be beneficially reused, they must be disposed of. The commenter further added that the cost and adverse environmental effects associated with that disposal would be further exacerbated by the fact that building materials and wallboard manufacturers would be forced to purchase natural gypsum instead of reusing the plant's byproducts. The commenter stated that, also, the more plants that are required to install activated carbon injection, the less gypsum would be available for use in wallboard manufacture–and the more mining that would be required. The commenter further stated that this major increase in mining activity would have additional significant adverse environmental impacts. The commenter stated that, finally, vast amounts of activated carbon will need to be produced and transported to support wide-spread application of ACI technology for the control of Hg emissions. Accordingly, notwithstanding recent developments in ACI technology, the commenter believed that it would be inappropriate for EPA to base its Hg removal program on broad use of ACI without first considering the serious environmental impacts associated with disposal of millions of tons of new solid waste per year, as well as the environmental impacts associated with production and transport of activated carbon, and the mining of gypsum to replace that which currently comes from scrubber gypsum. The commenter stated that indeed, § 112(d)(2) and § 111 (d) both specifically require EPA to consider such "non-air quality health and environmental impacts" when setting standards, thus mandating that EPA consider such effects before it can set standards that would require ACI.

Response:

EPA appreciates the commenter's input to the record on the status of control technologies. EPA also notes that ACI with a pulse-jet fabric may be installed upstream of wet scrubber. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric

Utility Boilers: An Update, EPA/Office of Research and Development, March 2005). Given that the first phase cap is set at the Hg co-benefits of CAIR, EPA does not project significant amount of ACI to be retrofitted until the 2018 timeframe. With regard to demand for activated carbon, EPA notes that markets respond to the demand for materials, much like under the NOx SIP call supply for catalyst increased with demand. See Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA, October 2002, in docket.

Comment:

One commenter (OAR-2002-0056-5548) stated that the cost of activated carbon could significantly increase if the demand exceeds the supply. Depending on the final carbon specifications, the annual excess activated carbon capacity is 60,000 tpy (US), 30,000 tpy (Germany), and 60,000 tpy (China) for a total worldwide excess capacity if 150,000 tpy. EPA's IPM modeling projects that 13 GWe of ACI could be installed by 2010. At a 15 lb/MMacf injection rate, 13 GWe of capacity is equivalent to a consumption of 130,000 tpy of activated carbon. This is about 87 percent of the worldwide excess capacity. At a 10 lb/MMacf injection rate, 13 GWe of installed ACI would consume about 87,000 tpy of activated carbon or 58 percent of worldwide excess capacity. This analysis assumes that ACI is installed only on units equipped with CS-ESPs (a conservative assumption). If a significant fraction of units were equipped with FF, then the carbon injection rate would be lowered to 4 to 5 lb/MMacf. If all units retrofitted with ACI were equipped with FF, then the projected annual carbon usage would be 43,500 tpy, which is 72 percent of the excess US capacity.

If ACI installations were to exceed about 15-20 GWe, then the demand for activated carbon would exceed the supply and the delivered cost could increase dramatically. Greater demand could be offset by the construction of additional activated carbon production capacity. For example, RWE is one of the world's leading producers of activated carbon. Their product, "HOK," has been tested successfully for Hg reduction at power plants in the U.S., and is used for similar purposes in Europe. According to Juergen Wirling, RWE's international sales manager, "if appropriate supply and purchase agreements are concluded and economic efficiency is given, an [additional] annual delivery quantity of over 100,000 tonnes of Activated Lignite will be possible. A prerequisite here is that for sales planning purposes or the initiation of measures aimed at stepping up production, a minimum lead time of three to four years will be available. The [RWE] annual production capacity of Activated Lignite already amounts to approx. 200,000 tonnes today. The raw material lignite is extracted from the Group's own surface mines, so that, in this respect too, sufficient security is provided."

These data indicate that, while the supply of activated carbon is marginally sufficient to meet projected near-term needs of about 10 GW capacity, there is reason for concern if ACI installations exceed expectations, and for the adequacy of longer term supply, if levels of ACI usage reach those projected by various modelers. EPA should consider explicitly the elasticity of ACI supply and demand in modeling the cost of ACI applications.

A second issue is the development of promoted (e.g., brominated) activated carbons. According to NORIT, brominated carbon would cost about 30 percent more than the current NORIT FGD costs of about $0.50/lb delivered, or $0.65/lb to $0.70/lb delivered. However, if, as

projected based on recent research, the brominated carbon dosage is one-seventh the standard carbon dosage for equivalent Hg removal, the cost of ACI would be significantly lower using brominated activated carbon. Assuming a 10 lb/MMacf dosage for NORIT FGD and $0.50 lib carbon cost and a 1.42 lb/MMacf dosage for the brominated carbon and a $0.70 cost, the use of brominated carbon would lower the sorbent cost by a factor of five.

There have been a number of intermediate term (two week to one month tests) tests of brominated carbon. The Hg removal at a site burning PRB coals and equipped with a SDA/FF averaged 93 percent at an injection concentration of 1.2 lb/MMacf. The results support the significant reduction in carbon dosage rate. At the recent PowerGen Conference, Hg reduction vs. injection rate performance data were presented. For a plant burning PRB coal and equipped with a CS-ESP, >90 percent Hg reduction was achieved at a brominated carbon injection rate of about 1.5 lb/MMacf. This is significantly better performance than NORIT FGD, which achieved 75 percent reduction at an injection rate of about 6 lb/MMacf. For a 500 MWe boiler with a SDA/FF burning a PRB coal, the NORIT FGD would cost $4,000,000 per year and the NORIT brominated carbon would cost $1,000,000 per year. The Hg removal cost effectiveness was lowered improved from $8,000/lb to $2,000/lb. Questions remain about the environmental impact of using brominated sorbents, but the performance and cost improvements suggested by these results warrant further evaluation. EPA should evaluate the cost impacts of advanced sorbents using the IPM model because significant advances in sorbent technology are occurring.

Response:

Given that the first phase cap is set at the Hg co-benefits of CAIR, EPA does not project significant amount of ACI to be retrofitted until the 2018 timeframe. With regard to demand for activated carbon, EPA notes that markets respond to the demand for materials, much like under the NOx SIP call supply for catalyst increased with demand. See Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA, October 2002, in docket. EPA has included the examination of technology improvement in its analysis of the costs of the final rulemaking. EPA has performed a sensitivity analysis assuming the introduction of a second ACI using advanced sorbents, leading to lower capital costs. See sensitivity analysis in Chapter 7 of final CAMR Regulatory Impact Analysis. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5497) stated that it was inappropriate for an economic forecast to assume a decrease in fixed capital costs of Hg control technologies. The utility industry learned from its experience with SCRs that EPA's and state regulators' early estimates were far lower than actual capital costs. This is relevant because, like SCR, plant-specific ACI costs and balance of plant issues remain uncertain and actual costs will be driven by those factors. In addition, costs will have to be adjusted higher to reflect the changes in the price and availability of steel. In the late-1990s, Northeast States for Coordinated Air Use Management (NESCAUM) stated that most SCR applications would cost $80-90/kW. EPA's Acid Rain Division estimated capital costs between $40 75/kW and the Institute of Clean Air Companies

(ICAC) predicted capital costs around $50/kW. In 2004, EPA is still publishing cost algorithms that generally argue the capital cost is less than $100/kW. Two recent surveys to determine installed SCR equipment cost show actual incurred costs average $125-140/kW, and for some installations approach $200/kW.

From time-to-time, EPA and environmental groups assert that the costs of SO_2 control in the Acid Rain program "proves" that costs of pollution control equipment are always much lower than originally estimated. This argument is a red herring. The costs of the SO2 program declined because of extrinsic economic factors that are unlikely to be repeated in any other situation. The federal government deregulated the railroad industry in the early 1990s, thereby vastly reducing the costs of transporting western low sulfur coal to the east. Many utilities were able to switch fuel supplies and avoid control technology costs altogether. This hardly shows that SO_2 control technologies dropped considerably. A more apt comparison (but unlikely scenario) in this context would be an assumption that natural gas prices dropped so low that coal fired power plants were able to "lower" Hg control costs by switching from coal to natural gas.

A complete assessment of Hg control technology cost requires including the impact of elevated carbon in ash on solid byproduct management. Higher carbon in fly ash will compromise its market value, perhaps eliminating the resale option entirely, and requiring disposal and management. The utility industry has known for decades that when combustion NOx controls are utilized that higher carbon in ash can render fly ash unmarketable. This is especially true for concrete, which is the largest and most valuable byproduct use of fly ash. According to the American Coal Ash Association (ACAA), fly ash for sale as concrete supplement derives the highest resale value ($20-$45/ton), and comprises by far the largest end use category. Virtually all Portland cement is prepared with several additives to enhance the following features: it must be "workable" or easy to pore into forms and shape; undamaged by exposure to alternating freeze and thaw environments; and consume a minimum amount much water to maximize ultimate strength. The problem with carbon in fly ash is that it interferes with all of these features in concrete.

In general, carbon content of fly ash must be 5 percent or less to be marketable, which is generally achievable for most units that fire their design coal and have properly tuned combustion systems. However, injecting ACI will generally elevate carbon in fly ash by approximately 4 percent above the 3-4 percent that would otherwise be expected. This tends to render concrete made from such ash discolored, weakened, more difficult to work, and less durable in freezing climates. These problems would likely worsen with halogenated ACI.

The impact of elevated carbon in fly ash on the cost of using ACI for Hg control is due to both loss of revenue from the sale of fly ash and the costs of permitting and disposing of material that previously was sold. The commenter's comments previously assumed that 35 percent of the fly ash generated in the U.S. would be rendered unmarketable and incur a charge of $24/ton due to a revenue loss of $12/ton and a disposal and management fee of $12/ton. The commenter has now updated their prior estimates. The weighted value of the revenue from ash sales, using information from the ACAA, is about $24/ton. The costs of disposal can vary widely on a case-by-case basis, but information provided by the ACAA supports an average cost of $ 12/ton. Thus the cost to utilities that can do longer dispose of their fly ash because they are using ACI is probably closer to $36/ton.

Response:

See comment response above for discussion of EPA modeling assumption for control technology costs. *EPA also notes that ACI with a pulse-jet fabric may be installed upstream of wet scrubber. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).*

6. Analyses of Hg trading programs by EPA and commenters indicate that variations in the first phase cap level and timing of the cap impact when the final cap level will be achieved. Although banking in the first phase impacts the timing of achieving the second phase cap, it should not affect the cumulative Hg emissions reduction ultimately achieved. EPA is seeking additional information on the impact banking may have on the timing of achieving the second phase cap.

Comment:

One commenter (OAR-2002-0056-5561) stated that in addition, the commenter had the following specific comment on the environmental impacts of emissions banking, which is informed by the modeling that occurred within the commenter's Air Quality Dialogue. Modeling conducted in the commenter's Air Quality Dialogue indicated that emissions banking could be beneficial from an environmental standpoint, potentially resulting in important near-term emissions reductions and environmental improvements that could outweigh the additional time required to meet a second phase cap. In a scenario without a Phase 1 emissions cap (the Phase 2 cap was set at 10 tons in 2018), the modeling projects that firms would delay any action until the approach of the binding cap, resulting in 16 percent fewer reductions in Hg emissions on a cumulative basis through 2022 than under a comparable scenario that included a Phase 1 cap set at 26 tons. The cost savings from not having to meet a 26-ton Phase 1 cap were insignificant (net present value of $0.3 billion for the 2005 to 2030 period) in the scenario without a Phase 1 cap, and the modeling showed a spike in costs just before the compliance year. Of course, the relative environmental and cost advantages of banking would depend on the chosen cap levels and timing. The commenter expected the near-term environmental benefits of emissions banking would be reduced if the first phase cap is set at a co-benefits control level.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. The cap-and-trade program will include a provision for banking. See final rule preamble and Chapter 5 comment responses for further discussion of banking.

Comment:

One commenter (OAR-2002-0056-5510) said that in regard to banking and the timing of achieving the second phase cap, the commenter had proposed an alternative cap and trade program, which, among other things, significantly reduces the amount of banking that can occur

prior to 2018–increasing the likelihood that actual coal-based power plant emissions in 2018 will be 15 tons.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. The cap-and-trade program will include a provision for banking. See final rule preamble and Chapter 5 comment responses for further discussion of banking.

Comment:

One commenter (OAR-2002-0056-5493) stated that pursuant to these regulatory proposals, EPA intends to reduce Hg emissions from coal-fired power plants by 70 percent by setting a permanent 15-ton cap in 2018 regardless of the future growth in the energy sector. Thus, the cap would effectively become more stringent as more power plants are constructed in order to keep their collective emissions below 15 tons. EPA proposes to set the near-term Hg emissions cap in 2010 at a level that can be achieved through the installation of FGD and SCR units that will be necessary to meet 2010 caps on SO_2 and NO_x under existing cap-and trade programs. The commenter agreed with EPA that this "multi-pollutant" approach is the most effective and reasonable way to reduce emissions from coal-fired power plants in the near-term.

However, there is no provision in the proposed cap-and-trade approach that permits credit for reduction of Hg emissions achieved before the near-term cap become effective in 2010. The Building and Construction Trades Department (BCTD) of the AFL-CIO agrees with the comments submitted by the Unions for Jobs and the Environment on June 29, 2004, that a mechanism should be incorporated in the proposed rule that affords credit for reduction of Hg emissions in advance of the 2010 cap date. Such credit would encourage the installation and/or modification of technologies sooner than later thereby helping to avoid the inevitable last-minute crunch that will create an unnecessary burden on the limited supply of skilled manpower available to install FGD and SCR units.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. The cap-and-trade program will include a provision for banking. See final rule preamble and Chapter 5 comment responses for further discussion of banking. EPA is not including a provision for early reduction credits in the final rulemaking. See Chapter 5 response to comments for further discussion of ERCs.

Comment:

One commenter (OAR-2002-0056-5502) stated that emissions were projected to be 15 tons by 2020 in every Cap and Trade case examined using the EPMM and reported to EPA in June 2004. In the NODA, EPA characterized the 2020 emissions estimates reported for EPMM Cap and Trade scenarios as, variously, either 23 or 24 tons. Additional examples are provided

demonstrating the validity and robustness of the earlier projection of about 15 tons by 2020.

Response:

EPA has examined the commenters analysis and notes that its own analysis shows a more gradual emission glide path in meeting the second phase cap. See Chapter 7 of final rule RIA for further discussion of EPA emissions projections.

Comment:

One commenter (OAR-2002-0056-5535) stated that EPA seeks comment on a number of economic modeling analyses performed by different stakeholder groups. The commenter's primary comment on this aspect of the NODA was that it fails to honor the commitment Administrator Leavitt made to the public: to ensure that the rule will be "done in a way that will maximize the level of reductions" based on the available technology. In particular, the NODA does not present any new EPA analyses of stricter MACT scenarios, much less examine the different control options put forward by stakeholder groups participating in the Utility MACT Working Group.

A second concern the commenter had regarding the various cap-and-trade scenarios that were modeled was that none ensures that actual emissions will be equal to, or lower than, the cap level by the date the cap goes into effect. For example, the Center for Clean Air Policy (CCAP) modeled a 7.5 ton cap in 2015, yet the results predict that 11 tons will still be emitted in 2020. EPA asks for comments on the so-called "glide path" of the reductions, and the commenter reiterated their earlier comments that the safety valve provision and the facilities' unrestricted ability to borrow from future allowance years means that emissions will continue to exceed the cap far into the future, perhaps indefinitely. EPA must recognize that the cap and trade options all result in a cumulative loading of Hg into the environment for 10 to 20 years longer than a proper MACT standard, in far greater amounts. This additional loading of a persistent, bioaccumulative metal is unacceptable.

With regard to the specific modeling results, the analysis that was of most interest to the commenter was the Cinergy Corporation's (Cinergy) "stringent MACT" modeling, and the commenter's assessment of that approach is discussed in detail below. Before turning to Cinergy's modeling, however, it bears reiterating our prior comments about the CCAP work. CCAP's report states:

> Tightening the mercury emissions-reduction cap from 15 tons in 2018 to 10 tons in 2018 is projected to increase total [three pollutant program] compliance costs by approximately 5 percent ($3.1 billion in net present value terms). Further tightening the cap by advancing the compliance date to 2015 would add approximately another 5 percent to total 3P costs, and reducing the cap to 7.5 tons in the same compliance period would increase total 3P costs by an additional 4 percent. In addition, even the most aggressive of these options (7.5 tons cap in 2015) has almost no impact on wholesale electricity prices both nationally (within 0.2 percent) and regionally (-1.5 to 2.1 percent), reflecting how the cost may not be passed on directly to wholesale electricity consumers. Cumulative mercury emission reductions increase between 8 and 28 percent through

2022 with these more aggressive caps and timetables. Moreover, the impact of such changes on national and regional coal production is slight (-1 to 5 percent).

What that means for present purposes is that even if EPA persists in its unlawful scheme to regulate Hg pollution under section 111 of the Clean Air Act (which of course it should not do), a much more stringent approach is economically feasible.

Cinergy modeled a MACT control regime becoming effective in 2008 and reducing approximately 39 tons of annual Hg emissions (an 81 percent cut). Even though Cinergy's assumptions included higher capital costs and less Hg co-control by NO_x and SO_2 controls than EPA's modeling, and also included the extreme assumption that activated carbon injection (ACI) would not be available until after 2010, the commenter note that the average annual costs of control in 2010 and 2020 (calculated by dividing the net present value of $130 billion in 2010 and 2020 by 20 years) are on the order of $6.5 billion, which is economically feasible. Although the NODA states that Cinergy's modeling of this scenario resulted in significant increases in power prices and fuel prices in the short term, the commenter was unable to verify that this is indeed the case as the full model results inexcusably were not included in the public version of Cinergy's comments. The public deserves the right to see the concurrent SO_2 reductions of Cinergy's stringent MACT scenario to see if the benefits of this scenario outweigh the costs. The commenter had every reason to believe they do.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. Discussion of EPA's cost modeling can be found in Chapter 7 of the final CAMR RIA. Further details on commenters analysis are found in their submittals to the docket.

Comment:

The commenter (OAR-2002-0056-5455) noted that in studying Table 1 of the NODA, it appeared that it really was not much more expensive to control Hg emissions to 7.5 tons per year rather than 15 tons per year. A two-phase cap of 15 tons was projected to cost $3.3 billion by 2010 and $6.7 billion by 2020. But a two-phase cap of 7.5 tons was expected to cost $4.6 billion by 2010 and $7.1 billion by 2020. The difference by 2020 is only 6 percent. For all of EPA's sloppy calculations, incorrect assumptions, and failure to carry out a proper MACT determination, it only made a 6 percent difference in cost. It would be hard to overstate the level of disgust in the Indian community over the way EPA has handled this rulemaking.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. Discussion of EPA's cost modeling can be found in Chapter 7 of the final CAMR RIA.

Comment:

The commenter (OAR-2002-0056-5404) stated that the NODA recognizes that "[a]lthough banking in the first phase impacts the timing of achieving the second phase cap, it should not affect the cumulative Hg emissions reductions ultimately achieved under the program." 69 Fed. Reg. 69870. The commenter stated that EPA nonetheless requests comment on "the impact banking may have on the timing of achieving the second phase cap." Id. The commenter strongly supported unrestricted banking of Hg allowances; according to the commenter, indeed, there is no policy basis to restrict trading, even if unrestricted banking delays the date by which sources achieve source-specific limits that correspond to the Phase II emissions reductions on an annual basis.

The commenter stated that in addition to having no impact on the cumulative Hg emissions reductions ultimately achieved under a cap-and-trade program, if unrestricted banking means (as it likely will) that the Phase II cap will not be achieved exactly by 2018, this will be the case because Phase I Hg reductions will have gone beyond what Phase I requires. According to the commenter, that is, Hg allowances have a vintage year before which they cannot be used; thus a source can exceed the Phase II cap in 2018 only if it has reduced emissions beyond what is required under Phase I, carrying Phase I allowances over to Phase II. The commenter stated that these greater emissions reductions achieved during Phase I arguably are preferable for the environment, but at a minimum are neutral from an environmental perspective.

The commenter stated that the fact that emissions in Phase II may exceed the cap because of surplus reductions in Phase I can pose no adverse environmental consequences unless the pollutant at issue poses significant acute health risks. According to the commenter, Hg is not such a pollutant; environmental issues associated with Hg result from the deposition of Hg on water is converted to methylmercury (MeHg), which in turn can bioaccumulate in fish, and subsequently in people. The commenter stated that this is a long-term process, however, and concerns regarding Hg emissions should focus on cumulative environmental loadings over time, not on local, short-term emissions. According to the commenter, unrestricted banking cannot, by definition, allow cumulative emissions over the life of the program to exceed what they would be if banking were restricted. The commenter stated that, thus, no policy basis exists for any restriction on the banking of Hg emissions.

The commenter added that, moreover, there are significant policy benefits to allowing unrestricted banking. The commenter stated that banking can provide significant cost savings with respect, as well as promoting efficient emissions reduction. The commenter added that unrestricted banking will also provide affected sources with valuable compliance flexibilities and incentives for technological development. The commenter stated that, as noted in their June 24 comments, no currently available control technology exists that would enable the power generation sector to achieve a 15 ton cap. The commenter further stated that by permitting unrestricted banking, system owners and operators will have the incentive to reduce Hg emissions earlier and in amounts greater than the rule requires in order to bank allowances that they can use to facilitate compliance at the beginning of Phase II. The commenter stated that these allowance surpluses will give sources the compliance flexibility they need to experiment with promising new technologies–which may have the potential to reduce Hg emissions efficiently and cost-effectively–without fear of consequences associated with non-compliance. According to the commenter, unrestricted banking will thereby ease the regulatory burdens associated with achieving the 2018 cap because sources will have greater flexibility to identify

and implement new, promising control technologies. The commenter stated that, moreover, as noted above, unrestricted banking results in no environmental disbenefits. The commenter further stated that to the extent that Hg emissions from power plants could be identified as a human health concern, such concern would be limited to the contribution of those emissions to the global pool. The commenter stated that in any event, a flexible cap and trade program with unrestricted banking would be an effective mechanism to reduce the contribution of the power generation sector to the global Hg pool.

The commenter noted that, in sum, permitting sources to retain unused allowances from one calendar year for use in a later calendar year will encourage early emissions reductions, provide flexibility to affected sources to meet environmental objectives, and facilitate the development of new, innovative Hg reduction control strategies. The commenter stated that given that unrestricted banking provides the foregoing benefits with no corresponding environmental disbenefits, EPA should allow unrestricted banking in the final rule.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. The cap-and-trade program will include a provision for banking. See final rule preamble and Chapter 5 comment responses for further discussion of banking.

Comment:

One commenter (OAR-2002-0056-5548) stated that based on their review of the available information, the commenter could find no plausible basis to employ any allowance allocation adjustment factors by coal rank for any cap that is in effect after 2014. The level of the cap is irrelevant; because by 2014 EPA projects, and proposes to rely upon, the commercial availability of Hg-specific control technologies, and these technologies are expected to deliver reasonably similar removals across all coal ranks.

Response:

The final rule takes into account the different levels of mercury control that lignite, bituminous, and subbituminous coals can achieve using existing NOx and SO_2 controls and uses coal adjustment factors for determining the state emission budgets and determining unit-level allocation under EPA's example allocation methodology for States. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Indian Country Emissions Budgets, EPA, March 2005.

Comment:

One commenter (OAR-2002-0056-5548) stated that bituminous users and subbituminous users that do not comply with their Hg reduction obligations through co-benefits will have to purchase allowances under the trading program, and that price will not vary depending on the rank of coal burned by the allowance purchaser. That is the very point of a trading program,

which is, as EPA notes, "cost-effective," because it allows sources that can reduce Hg more cost-effectively to do so, and pass those savings on to other units that cannot make reductions that are as cost-effective. In other words, under a trading program, sources with the lowest compliance costs bear the burden of control.

There are those who might be concerned about allowance availability on a unit-specific basis, even though co-benefits reductions will generate adequate allowances on an aggregate basis. While this potential concern is one that is equal across coal ranks, because there will be many bituminous units that will be relying on allowance purchases for compliance as well as units burning low rank coals, this concern is also easily addressed through restrictions on banking. If EPA makes adjustments to its banking provisions to largely prohibit banking, particularly in the first few years of any co-benefits program, all allowances will be held on a "use it or lose it" basis, and consequently will be sold to those that need them for compliance. The commenter did not believe that allowance hoarding is a likely outcome, nor one that would become an extended practice, but a phase-in provision for banking whereby banking is restricted in the early years would certainly address that issue. As an alternative, and likely a better solution, EPA could develop a conditional restriction on banking whereby allowance banking is prohibited unless the allowances are first offered for sale at an annual EPA auction, and, if not purchased by one that needs them for same year compliance, may be banked without restriction. This approach would only restrict banking to the degree necessary to ensure that all sources that must rely on allowance purchases to comply under a co-benefits approach can obtain them. EPA can also help address allowance availability concerns, and provide an incentive for early adoption of Hg-specific control technology, by restricting banking to those reductions that result from the application of Hg-specific control technology, i.e., beyond simple co-benefit reductions.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. The cap-and-trade program will include a provision for banking. See final rule preamble and Chapter 5 comment responses for further discussion of banking. The final rule takes into account the different levels of mercury control that lignite, bituminous, and subbituminous coals can achieve using existing NOx and SO_2 controls and uses coal adjustment factors for determining the state emission budgets and determining unit-level allocation under EPA's example allocation methodology for States. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Indian Country Emissions Budgets, EPA, March 2005.

Comment:

One commenter (OAR-2002-0056-5497) noted that EEI commissioned Charles River Associates (CRA) to perform a number of sensitivity runs using EPMM to identify those factors that affect the "glide path" and the timing in achieving the second phase cap. CRA's analysis is being submitted as part of EEI's NODA comments (see OAR-2002-0056-5469). The commenter refers EPA to EEI's NODA comments for the detailed presentation of CRA's work.

Briefly, CRA's work shows that the two factors that have the greatest impact on the

"glide path" and the timing of emission reductions to achieve the second phase cap emission level are: (1) how closely the first phase cap is set to the true level of co-benefits and (2) the duration of the first phase cap. If the first phase cap is set below the level of true co-benefits, then more banking would occur during the first phase and full achievement of the second phase cap emission level would occur later. The longer the duration of the first phase cap, the greater the amount of banking and, again, deferred achievement of the second phase cap emission level.

Other factors with smaller effects on the "glide path" are the assumptions one uses about the growth in the use of low sulfur coal and the stringency of the second phase cap. Changes in assumptions about the growth of the use of low sulfur coal primarily affect the level of predicted co-benefits in the first phase. The stringency of the second phase cap affects the ultimate cost of compliance and hence the desire of companies to put off the capital costs of second phase compliance by early banking. CRA found that changes in technology cost assumptions do not have a major impact on the "glide path."

These sensitivity results continue to point out the wisdom of the alternate Hg cap and-trade proposal offered by the commenter and a variety of other industry commenters. That proposal would not set a "hard" cap" for the first phase; rather, the Hg co-benefits would be what they are. Mercury trading would not be allowed during the first phase, but early reduction credits could be earned for installing Hg-specific control equipment. A second phase would begin in 2015 with a cap of 24 tons of Hg per year. In the second phase, Hg allowances would be allocated and Hg trading would occur. The third phase would begin in 2018 with a cap of 15 tons per year.

Under this industry proposal, the first phase cap could not be set at a level below the true co-benefits level; thus, the amount of banking could be expected to be less. Indeed, the only credits that would be accrued from 2010 to 2015 would be those associated with the early installation of Hg control equipment. Providing for early reduction credits would foster early reductions in Hg emissions and assist in identifying and solving technical issues that will undoubtedly arise when a new technology is installed. Beginning the second phase in 2015–only three years before the proposed third-phase 15-ton cap would take effect–would limit the period during which allowances could be banked, making it likely that full achievement of the third phase cap emission limit would occur in or not long after 2018.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. The cap-and-trade program will include a provision for banking. See final rule preamble and Chapter 5 comment responses for further discussion of banking. EPA is not including a provision for early reduction credits in the final rulemaking. See Chapter 5 response to comments for further discussion of ERCs.

Comment:

One commenter (OAR-2002-0056-5469) noted that the EPMM model runs reported in the commenter's earlier submission (see OAR-2002-0056-2929) projected that emissions of Hg

would reach the level of the Phase II cap of 15 tons by 2020. It has been widely reported that EPA's analysis of the same scenario using its own assumptions and the IPM model did not come close to reaching the level of the Phase II by 2020, or even by the end of its 2026 model period. CRA's report, submitted with the commenter's comments, provided an explanation of the likely reasons for EPA's assumptions to have produced such a different glide path for the same scenario. There were three basic reasons:

1. EPA set the Phase I cap at 34 tons, which was equal to "co-benefits" under EPA's modeling assumptions. Industry's assumptions implied that "co-benefits" were substantially higher, at 39.9 tons. The main reasons for these differences in co-benefits were:

    a. EPA assumed greater incremental Hg control resulting from addition of FGD, and from adding SCRs to units with FGDs as well, particularly for subbituminous coals, but also for FGDs added at bituminous-fired units.
    b. Even without consideration of the Hg co-benefits from FGDs, EPA's assumptions led to a greater propensity to meet SO_2 caps through capital-intensive FGDs rather than through use of lower-sulfur coals.

2. EPA's marginal cost curve for addition of ACIs (to achieve Hg controls beyond the co-benefits level) was higher and steeper than the technological cost and effectiveness assumptions used by industry.

The commenter noted that CRA explained how the net impact of these differences in assumptions was that EPA's model would find it cost-effective to bank much larger amounts during Phase I of the proposed Hg cap-and-trade policy option (when reductions could be met largely via co-benefits that were relatively cheap compared to those assumed by industry) and to avoid for a relatively longer time the deeper cuts of Phase II (which would require ACI investments that were relatively more expensive than assumed by industry). In other words, when the Phase I cap is set closer to co-benefits, the glide path to the final level of the cap will be more extended during Phase II. The more costly the Phase II cap is to meet, the more extended the glide path will be (i.e., more banking will occur in Phase I, thus lengthening the period of time until emissions would reach the final cap). By setting the Phase I cap at its model's estimated level of co-benefits, and having a Phase II cap that would be relatively expensive to meet, EPA's was maximizing the chances that its model would project a long delay before annual emissions near the Phase II cap.

Industry analyses did not find this to be a realistic glide path if the cap were to be set at 34 tons, for the simple reason that industry's data indicate that a 34 ton cap would be far below the low-cost zone of co-benefits, and so the Phase I cap would quite expensive to meet in its own right. Thus, far less banking would be warranted in Phase I, and industry projects a quicker glide path to the proposed Phase II cap, with a much smaller bank to deplete, and thus relatively prompt attainment of the actual level of the Phase II cap.

The commenter stated that in response to the NODA, CRA has prepared a number of additional sensitivity cases using EPMM to substantiate the above logic, and to better elucidate the particular parameters that might most alter the length of the glide path to a Phase II cap. The

commenter explored the role of (a) uncertainties in EPMM assumptions that fundamentally determine the co-benefits level; (b) the stringency of the Phase II cap relative to the Phase I cap; (c) impact of setting the Phase I cap closer to the expected level of co-benefits; (d) shortening the duration of Phase I, with alternative assumptions about the timing and phase-in of an ultimate 15 ton cap; and (e) the role of rate of technological improvement. Except where noted, all of the runs described in this section were prepared with the extended version of EPMM that includes a terminal model period at 2030. Thus, the 2020 emissions results that the commenter reported here are not from a terminal period. Also, all of the runs assume a 2.5 percent per annum (p.a). reduction in the variable cost of Hg control technologies except where the commenter specifically explore the role of alternative assumptions about technological change (in Section III, see Document ID No. OAR-2002-0056-5469).

The commenter found that the most important determinants of the glide path are how close the Phase I cap is to the level of co-benefits, and the duration of Phase I. These have the most direct connection to the size of the bank that can be built up at relatively low cost prior to entry into Phase II, and that, in turn, most directly affects the length of time before annual emissions must actually be at the Phase II cap. The commenter also found that the effects on the glide path of setting a Phase I cap set at or near co-benefits levels can be offset effectively by an earlier introduction of Phase II, or even an interim cap before the 15 ton level. This two-pronged adjustment to the proposed Hg cap appears to strike a good balance between a reasonable rate of introduction of new Hg control technology that can maximize the potential benefits of technological advancement, and avoiding significant delays in when actual annual emissions would be at the level of the 15 ton cap.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. EPA has examined the commenter's analysis and notes that its own analysis shows a more gradual emission glide path in meeting the second phase cap. See Chapter 7 of final rule RIA for further discussion of EPA emissions projections.

Comment:

One commenter (OAR-2002-0056-5469) noted that they previously identified uncertainty in the amount of FGD that would be installed versus use of lower-sulfur coals to meet SO_2 caps as one of the possible uncertainties in our estimate of co-benefits. One assumption in EPMM that might affect the mix of SO_2 compliance choices regards the availability of lower-sulfur coals. The standard EPMM assumptions have been to allow up to 2 percent p.a. growth in use of coals in each of several coal quality categories. However, recent experiences in coal markets have suggested that the lowest-sulfur forms of Eastern bituminous coals may not have even that much potential for growth in supply without major cost increases.

The commenter decided to look at how the FGD choices might be adjusted if this coal were only allowed to grow at 0.5 percent p.a. All other coals continued to face 2 percent p.a. growth limits, except for the high-sulfur bituminous coals, which were no longer constrained at all. This run did produce a fairly dramatic increase in the quantity of FGDs installed by 2010,

and a correspondingly lower co-benefits level. In 2010, it projects a co-benefits level of 38.9 tons, as compared to 40 tons under our standard coal growth assumptions. While there are more FGDs in this case, there is a more gradual introduction of ACIs. The net effect is only a very modest change in the glide path. Emissions in 2020 are at 15.6 tons, compared to 15.4 tons in the standard case reported in Section I.A. (see OAR-2002-0056-5469).

This scenario suggests that the role of a preference for FGD in determining co-benefits and a glide path to Phase II may be fairly minor. The commenter found that industry's estimate of 2010 co-benefits might be as low as 38.9 tons, rather than the 39.9 tons originally reported (which is now estimated at 40.0 tons using the version of EPMM with the extended model horizon). This difference does not affect the estimated present value cost of the Hg cap-and-trade proposal, which is $1.8 billion (1999 dollars) for both the lower or higher assumptions about low-sulfur bituminous coal availability.

Another area of substantial uncertainty on co-benefits relates to the specific assumptions that are made about the reductions that are associated with different configurations of PM, SO_2, and NO_x controls. In particular, there has been much debate over whether SCRs produce additional Hg reduction when added to units with an FGD that are burning a lower rank coal. EPRI reports in its comments on the NODA that there may be some new evidence that there could be a very small amount of co-benefits in such units. Although the evidence is from a single plant, and may not apply to all low-rank configurations, the commenter tested the effect of adding a 5 percent co-benefit from SCR to all subbituminous and lignite-burning plants. This had almost no impact at all on our co-benefits estimates: the 40.0 ton estimate from the base model was reduced to 39.9 tons.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. EPA agrees that different modeling assumptions can impact the projection Hg co-benefits from NOx and SO2 controls under CAIR. As discussed in the NODA, for the final rulemaking analysis, EPA has made changes to some of its co-benefit assumptions for subbituminous units with SCR and FGD controls. EPA is also using a newer version of EPA's IPM for the final rulemaking. Changes to the modeling assumptions can found in the IPM documentation in the rulemaking docket (see Documentation Summary for EPA Base Case 2004 (v.2.1.9) Using the Integrated Planning Model, EPA, October 2004). EPA has examined the commenter's analysis and notes that its own analysis shows a more gradual emission glide path in meeting the second phase cap. See Chapter 7 of final rule RIA for further discussion of EPA emissions projections.

Comment:

One commenter (OAR-2002-0056-5469) noted that another possible factor that the commenter posited could lengthen the glide path is how stringently the Phase II cap is set relative to the stringency of the Phase I cap. To explore this possibility, the commenter considered the impacts of a Phase II cap set at 7.5 tons rather than 15 tons, while keeping the Phase I cap at 34 tons, the presumed level of the proposed Clean Air Mercury Rule (CAMR).

This would have the effect of making the marginal cost of meeting the Phase II cap once the bank is depleted much more costly relative to the marginal costs of exactly meeting the Phase I cap. The result should be an incentive to bank more during Phase I, in order to reduce the rate of increase of marginal costs of control (also called emissions prices) back to about the corporate discount rate. If this were to happen, the glide path to the Phase II cap would be lengthened.

This is exactly what the commenter found in this scenario. The marginal costs, Hg emissions, and cumulative amount of Hg emissions banked are shown in Table 4. The most dramatic effect of this scenario is that Phase II is not only delayed beyond 2020, but projected emissions are still well above the Phase II cap through the end of the terminal model period: projected emissions in 2020-2029 are 11 tons, and they are still 9.3 tons for the entire period 2030-2049. The 7.5 ton cap is never fully met until the first year after the model stops accounting for costs of control, in 2050. This delay is accomplished by accumulating a bank exceeding 86 tons during Phase 1. Even with this lengthy delaying action, the marginal cost of controls in 2020 is over $45,000/lb (1999 dollars).

The commenter also found that the 7.5 ton Phase II cap increases the present value of the policy's cost quite significantly. Our estimated present value (through 2020) of costs of the proposed Hg cap-and-trade policy is $1.8 billion (1999 dollars). With the same assumptions, a 7.5 ton cap in Phase II is estimated to be $4.6 billion. Tightening the Phase II cap in 2018 from 15 tons to 7.5 tons increases policy costs by 160 percent.

Table 4. Results of Scenario with 7.5 ton Phase II Cap in 2018

	Hg Emissions (tons per year)	Hg Bank at Beginning of Period (tons)	Marginal cost of Hg controls in Period
2004	44.6	na	na
2008	43.1	na	na
2010	28.3	0.0	$25,691
2012	23.6	11.3	$28,872
2015	19.3	42.4	$34,435
2018	15.4	86.6	$41,098
2020	11.0	70.9	$45,586
2030	9.3	35.6	$99,693

The commenter also ran a case where no banking was allowed during Phase I, thus forcing the model to actually meet the 7.5 ton cap in 2018 and thereafter. The purpose of this was to determine the sensitivity of marginal costs to a cap of 7.5 tons. This case produced marginal control costs of $120,000/lb in 2018, and $94,000/lb in 2020 (both 1999 dollars). The falling marginal control cost reflects the effect of the 2.5 percent p.a. decline in variable O&M costs of ACI. This rate of decline is not insignificant, but certainly insufficient to make attainment of a 7.5 ton cap occur without very high allowance prices.

The stringency of the 7.5 ton cap also is reflected in terms of its implications for retrofitting. When the 7.5 ton cap is met in 2018, fully 78 percent of existing coal capacity has been retrofitted by ACI at 90 percent controls, in addition to the usual large number of FGD and

SCR installations (about 107 GW and 56 GW of additional FGDs and SCRs, respectively, are also added by 2018). Clearly most plants are installing ACI as well as FGDs and SCRs.

The commenter found that this was a particularly interesting scenario in light of the comments that were submitted to EPA in June 2004 by the Center for Clean Air Policy (CCAP), and which were summarized in the NODA. The NODA summarizes CCAP's views based on a comparable model run with IPM as "concluding that the incremental changes in the timing and stringency of a Hg cap have, in CCAP's opinion, relatively modest cost implications." The commenter reviewed the detailed results of CCAP's runs, and found that our results are actually very similar to those found by CCAP for the 7.5 ton cap case:

- CCAP's scenario for a 7.5 ton cap in Phase II (with Phase I banking) projects that emissions in 2020-2025 would still be 11.3 tons and the marginal cost of control in 2020 would be $88,060/lb (1999 dollars).

- CCAP's results for a 7.5 ton cap in Phase II (with no Phase I banking) projects that the marginal cost of meeting the 7.5 ton cap would be $165,500/lb in 2018 and $129,500 in 2020 (1999 dollars).

- CCAP's costs of having a more stringent 7.5 ton cap in 2015 is also at least 150 percent more costly than a 15 ton cap in 2018, even based on much lower EPA gas price assumptions.

In brief, CCAP's analysis finds the 7.5 ton cap more costly to achieve than does CRA's analysis. There is obviously a "knee in the curve" of the marginal control costs at a cap level greater than 7.5 tons. The commenter therefore conclude that EPA's interpretation of the CCAP results, that the timing and stringency of the Hg cap "have relatively modest cost implications" is a judgment that the commenter found inconsistent with CCAP's own modeling results.

CCAP reports that it considered alternative levels of the Phase II cap in an effort to "identify a possible middle ground solution... in which a less stringent Phase I target is traded off against a more stringent Phase 2 target." The commenter's analyses suggested that increasing the stringency of the Phase II cap can be counterproductive. It can delay attainment of the Phase II cap for extended periods, while creating a much more rapid rate of investment in the emerging technology that may exacerbate efforts for a measured and cost-effective phase-in process. If one goal is to design a policy that will enable a gradual phase-in of investments in emerging forms of control technology, thereby maximizing the opportunities and incentives for technological improvements to be gained, then it does not make sense to have a stringent Phase I cap, but it also does not make sense for the Phase II cap to be very stringent relative to the Phase I cap. A proposal for a cap as tight 7.5 tons is inconsistent with CCAP's much more important point, that a gradual phase in period, and incentives for early action are desirable elements of a sound policy where a control technology is still in an emergent stage.

Response:

EPA has examined the commenter's analysis in context of the final rulemaking. EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38

tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale.

Comment:

One commenter (OAR-2002-0056-5469) stated that there are some important merits to setting the Phase I cap at a level close to the "true" co-benefits levels. Most importantly, development, testing, and commercialization of Hg control technology for electric generating units is still at an early stage. The difficulties of achieving various levels of Hg control across the universe of generating units are highly uncertain and there is little if any experience with commercial installation. Because of this, rates of technological improvement in the technology are very high and a gradual phase-in helps motivate more intensive research, while also enhancing potential for carrying the learning from the first several installations into the wider set of installations that will come with time. At the same time, there is a risk that setting the Phase I cap at the "true" co-benefits level will create a longer-than-desirable glide path will be to the Phase II cap level.

Below, the commenter discussed results of a couple of scenarios evaluated to substantiate this point, and then the commenter turned to an alternative that more effectively resolves the glide path concern while preserving the benefits of setting Phase I cap at the "true" co-benefits level (see OAR-2002-0056-5469).

In CRA's analyses, the "true" level of co-benefits emissions in 2010 is either 38.8 tons or 40 tons. It is 38.8 tons in 2010 under the assumption of 0.5 percent maximum annual growth in low-sulfur bituminous coal, and it is 40 tons in 2010 under the assumption of 2 percent maximum annual growth in the same. The commenter's analyses of EPA's proposed cap-and-trade policy option, however, have used 34 tons as the Phase I cap. The commenter had used this value because EPA stated in its notice of proposed rulemaking that it would set the Phase I cap at the co-benefits level, and also that it estimated co-benefits to be 34 tons. A cap must be set at a well-defined level, and cannot vary depending on one's views about what might constitute the intended goal of co-benefits. Although 34 tons was not the "true" co-benefits level in our model, there is no reason to believe that EPA would select a Phase I cap at any level other than what *it* estimated as "true" co-benefits (see OAR-2002-0056-5469).

The commenter noted in our earlier submissions that EPA's projected glide path would be much longer than that projected by EPMM because the 34 ton cap was achievable solely by "true" co-benefits in EPA's modeling, but was much lower than the EPMM co-benefits level, and therefore more costly to meet in CRA's modeling. EPA's model would thus project much more banking in Phase I than would EPMM, thereby delaying full implementation of Phase II emissions levels in the Agency's runs. In the current analysis, the commenter simulated this effect in the EPMM model by running scenarios where the commenter set the Phase I cap at EPMM's projected co-benefits levels, for the two sets of coal assumptions, respectively. The commenter left the Phase II cap at 15 tons, since this value appeared to have no connection to particular model assumptions.

Tables 5 and 6 contrast the timing of ACI and FGD installations, respectively, for the case of Phase I being set by the co-benefits level, and the case of Phase I being set at a 34 ton cap. Figure 3 presents the glide paths of Hg emissions for both coal constraint cases. The

predicted effect on the glide path is apparent. Projected emissions remain 2 tons above the Phase II cap until 2030 in the case where the Phase I cap is set at co-benefits. This is the largest single source of glide path sensitivity that the commenter had found for a 15 ton Phase II cap. It would appear to explain much of the difference between the CRA projections of 2020 emissions reaching the national target level, and the more extended period to reach that target that has been reported as the EPA finding.

As noted, the advantage of a cap at co-benefits levels in the early years is that it creates a better environment for a gradual and non-disruptive commercial phase-in of a technology that can best be described as still emergent. By setting the cap at this level, one creates desirable incentives for early action by allowing banking to occur. However, if the cap remains at the co-benefit level for an extended period of time, a relatively large bank may be possible to build up. This implies benefits from early reductions, but at the same time, it means that the rate of decrease towards the Phase II cap will be slowed. The best way to preserve the merits of a cap set at co-benefits level, while managing for a relatively prompt attainment of Phase II is to alter the length of Phase I. The next section turns to this prospect, exploring how the glide path can be managed while still setting the Phase I cap set at the estimated co-benefits level.

Table 5. Quantities of New ACI Retrofits by Time Period (MW)

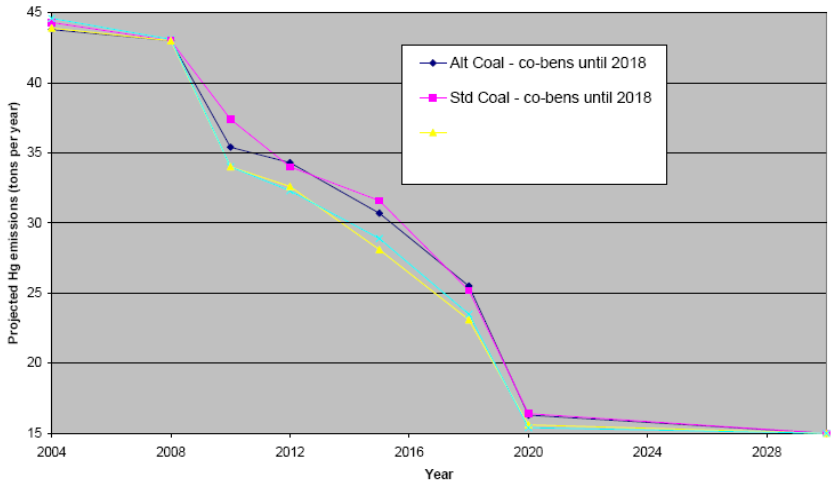
	Standard Low-S Coal Assumptions (2010 co-benefits=40 tons)		Low Supply Growth of Low-S Bituminous (2010 co-benefits=38.8 tons)	
Year	Proposed Policy: Phase I cap at 34 tons	Phase I cap at co-benefits	Proposed Policy: Phase I cap at 34 tons	Phase I cap at co-benefits
2004	1,050	244	1,050	244
2008	1	1	1	1
2010	16,835	4,537	11,660	5,679
2012	1,352	3,442	22,220	511
2015	16,398	11,092	19,848	15,158
2018	23,646	26,373	48,238	19,326
2020	49,079	51,067	22,220	56,514
2030	5,695	17,679	8,084	17,745

Table 6. Quantities of New FGD Retrofits by Time Period (MW)

	Standard Low-S Coal Assumptions (2010 co-benefits=40 tons)		Low Supply Growth of Low-S Bituminous (2010 co-benefits=38.8 tons)	
Year	Proposed Policy: Phase I cap at 34 tons	Phase I cap at co-benefits	Proposed Policy: Phase I cap at 34 tons	Phase I cap at co-benefits
2004	1,315	2,983	5,227	4,907

Year	Standard Low-S Coal Assumptions (2010 co-benefits=40 tons)		Low Supply Growth of Low-S Bituminous (2010 co-benefits=38.8 tons)	
	Proposed Policy: Phase I cap at 34 tons	Phase I cap at co-benefits	Proposed Policy: Phase I cap at 34 tons	Phase I cap at co-benefits
2008	8,159	5,936	6,907	6,677
2010	32,791	26,517	42,537	40,048
2012	13,678	19,816	6,457	8,686
2015	3,444	4,041	5,112	5,458
2018	12,024	10,710	17,893	17,481
2020	31,103	32,437	33,736	34,475
2030	15,330	16,187	9,511	10,219

Figure 3. Impact on Glide Path of Setting Phase I Cap at Co-Benefits (For Two Alternative Co-benefits Cases)



Response:

EPA has examined the commenter's analysis in context of the final rulemaking. EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. The first phase cap is based on EPA modeling of the Hg co-benefits of SO_2 and NOx controls installed for compliance with the CAIR rulemaking. See final rule preamble for rationale and Chapter 7 of final CAMR RIA for discussion of emissions projections.

Comment:

One commenter (OAR-2002-0056-5469) stated that four (4) additional scenarios were run that explored alternative timings of a Phase II cap that might be paired with a Phase I cap set at "true" co-benefits. Two scenarios were run assuming that the Phase II cap is implemented in 2015 instead of 2018 (one for each set of coal supply assumptions, and hence with different assumptions about co-benefits, to match the two scenarios described in comment above). The other two scenarios are the "Alternative Cap Proposal" (see OAR-2002-0056-4894) that commenter submitted to EPA on August 13, 2004 for each co-benefits case. This alternative proposal would strike an intermediate ground by tightening the cap in the period 2015-2017, but only to 24 tons, with the 15 ton cap following in 2018.

Figure 4 compares the glide path of each of these four scenarios to those in the previous section where the commenter set the cap at co-benefits in Phase I, but still allowing Phase II to enter force in 2018. Table 7 shows the associated quantities of ACI controls in each time step, which can be compared to the values in Table 5 as well. The early introduction of Phase II increases the rate of early action in Phase I, but still gets emissions to 15 tons by 2020. However, the commenter's proposed alternative scenario, with an intermediate cap at 24 tons, provides a similar reduction by 2020, but with a slower rate of investments in the early years, when the costs of control are the most uncertain.

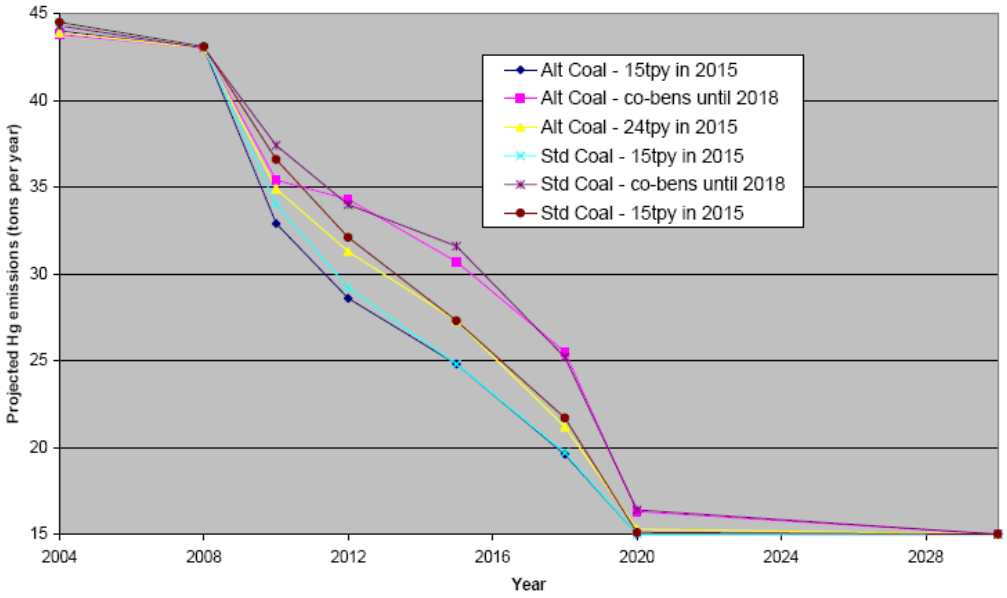
The estimated costs are fairly sensitive to the decision on level of the cap during 2015-2017. As a point of reference, the estimated present value of the Hg cap as proposed (i.e., 34 tons in Phase I, and Phase II starting in 2018) is $1.8 billion (1999 dollars). By allowing the Phase I cap to be set at co-benefits (as determined by the model), but continuing to keep Phase II in 2018, costs would fall to about $1.2 or 1.3 billion, and attainment of the Phase II cap could be delayed well beyond 2020. By introducing the 15 ton cap in 2015, costs would increase to about $2.6 or 2.8 billion, although emissions would be at 15 tons by 2020. In contrast, the alternative proposed by the commenter, would cost only $1.8 or 1.9 billion, and would still provide assurance of attainment of the 15 ton emissions level by about 2020.

Thus, a combination of a co-benefits based cap in Phase I with a shorter duration of Phase I provides better assurance against excessive costs during program start-up, as well as better assurance of reaching the 15 ton emission level somewhere in the 2020 time frame. If interim caps are used instead of bluntly moving the 15 ton cap forward in time, the policy costs need not increase, while still providing assurance of timely attainment of the 15 ton level of emissions.

The commenter's alternative cap proposal is very similar in nature to the simplistic sensitivity case that simply brings in a 15 ton cap by 2015. It has the same properties of requiring only cost-effective early action through 2015, yet bringing emissions to 15 tons promptly. The mechanism for accomplishing this effect was the same: by tightening the cap in 2015 in such a way that an allowance bank would not continue to accumulate at increasing rates for three additional years before the imposition of Phase II. The main differences of the

alternative proposed policy from simply introducing the Phase II cap by 2015 are:

Figure 4. Impact on Glide Path of Alternative Phase II Schedules in Combination with Phase I Set at Co-Benefits.



- Under the commenter's proposed alternative there would be no formally binding cap in the 2010-2015 time frame, providing further guarantees that early reductions would be

Table 7. Quantities of New ACI Retrofits by Time Period (MW) With Phase I Cap Set at Co-benefits Level, for Alternative Timings of Phase II Cap

	Standard Low-S Coal Assumptions (2010 co-benefits = 40 tons)		Low Supply Growth of Low-S Bituminous (2010 co-benefits = 38.8 tons)	
Year	15 ton cap by 2015	24 ton cap in 2015-2017	15 ton cap by 2015	24 ton cap in 2015-2017
2004	1,050	1,050	1,050	1,050
2008	1	1	1	1
2010	18,189	6,491	18,892	7,424
2012	15,715	12,029	18,204	14,466
2015	31,126	27,590	24,294	22,274
2018	17,417	23,780	22,792	26,686
2020	27,004	39,080	26,905	37,341
2030	4,044	5,024	2,902	5,469

against literal co-benefits rather than against an inherently uncertain estimate of what that co-benefit level would be. From a modeling perspective, where no uncertainties are simulated, this would have no impact on our results, but it obviously does have relevance to consideration of cost risks.

- Another difference that remains open to deliberation is the precise level of the cap in the 2015-2017 period. In one sensitivity case the commenter used 15 tons, whereas the alternative proposal by the commenter allows it to be 24 tons, substantially less stringent. The correct level to choose for the interim cap could be informed by whether it significantly alters the timing of attainment of the 15 ton emissions goal. The commenter's analyses indicate that a 24 ton cap in 2015 would ensure the prospects of prompt attainment of the 15-ton goal while maintaining a relatively gradual rate of Hg control investments during Phase I and keeping policy costs low.

It is important to note that the modest impacts on costs from an early introduction of Phase II only occur when this acceleration is combined with a Phase I period that is truly set at co-benefits (either by providing early reduction credits or by setting the cap at an accurate estimate of the literal co-benefits level).

Response:

EPA has examined the commenter's analysis in context of the final rulemaking. EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale and Chapter 7 of final CAMR RIA for discussion of modeling analysis.

7. Cinergy estimated a co-benefit of Hg reductions associated with implementation of the proposed CAIR at 38 tons in 2010; EEI Estimated a co-benefit level of 40 tons in 2010. EPA additional comment on the reasonableness of its IPM assumptions for co-benefit reductions. EPA also sought comment on appropriate emission modification factors (EMF)–a component of the estimated Hg co-benefit reductions.

Comment:

One commenter (OAR-2002-0056-5464) believed the modeled cost estimates were too high and the assumptions of co-benefits from the proposed Clean Air Interstate Rule were lower than even EPA's projections.

Response:

EPA has examined the commenter's analysis in context of the final rulemaking. EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale and Chapter 7 of final CAMR RIA for discussion of modeling analysis.

Comment:

One commenter (OAR-2002-0056-5332) stated that EPA requests comments on the "co-benefits" of Hg reductions associatewith implementation of the proposed CAIR. This issue is extremely important, as EPA is proposing to establish the Hg co-benefits level as the first-phase emission limitation of its section 111 proposal.

Initially, the Agency had estimated a Hg co-benefits level of 26 tons (down from 48 tons); that is, it estimated that air pollution control devices installed to reduce the emissions of pollutants other than Hg from coal- fired units would reduce Hg emissions by 22 tons, resulting in the incidental reduction of Hg emissions to a level of 26 tons. Based apparently on subsequent revisions to its modeling assumptions, EPA increased the co-benefits level to the current estimate of 34 tons; that is, it concluded that incidental Hg removal would be less than originally estimated, 14 tons rather than 22 tons. Now, some stakeholders are suggesting that the co-benefits level should be raised to something closer to 40 tons, meaning that incidental Hg reductions would be even lower (only eight tons). Apart from the technical justification or lack thereof for this co-benefits level (see discussion below), the commenter noted that a cap-and-trade program with a 40-ton cap would free a great many sources from the need to make any reduction at all in their emissions of Hg. It would also allow many sources easily to over control in Phase I, bank the excess allowances, and use the banked allowances in future control years. This would push back the time that the Phase II cap will ultimately be achieved even further than is the case under EPA's currently proposed cap-and-trade proposal.

Based on its modeling, EPA concludes that average Hg removal from existing air pollution control devices across all coal types and control configurations is currently approximately 36 percent (48 tons emitted versus 75 tons contained in coal). EPA currently estimates that with the controls installed to comply with the CAIR proposal, annual Hg emissions from existing air pollution control equipment will drop further, from 48 tons to 34 tons per year, which represents about a 29 percent reduction from current emissions.

However, EPA's estimate of Hg co-benefit levels reflect only incidental Hg reduction from control devices designed and operated to remove other air pollutants, such as SO_2, NO_x, and particulate matter, with no attempt to optimize their operation for Hg removal. The commenter believed that the capture of Hg by existing controls can be increased significantly, simply by optimizing reductions from equipment installed to control other pollutants. A great deal of work is being done on measures that can be taken to optimize Hg reductions from existing air pollution control equipment, including the injection of oxidants (e.g., chloride) into flue gas to promote the oxidation of elemental Hg from SCR at units burning lower rank coals (which are typically low in chloride levels), and the addition of chemicals to enhance the removal of oxidized Hg in wet FGD systems and to prevent re-emissions of Hg.

The commenter believed that the Hg co-benefits of CAIR should perhaps be reduced from EPA's current estimate of 34 tons; in other words, the commenter's view was that reductions in Hg emissions achieved as a co-benefit of efforts to control other pollutants are

greater than EPA currently estimates. By the same token, the commenter did not believe that there would be any justification for increasing the Hg co-benefits figure to more than 34 tons, as that would require the conclusion that other controls would not be as effective in reducing Hg emissions as the available data indicate.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. The first phase cap is based on EPA modeling of the Hg co-benefits of SO_2 and NOx controls installed for compliance with the CAIR rulemaking. See final rule preamble for rationale and Chapter 7 of final CAMR RIA for discussion of emissions projections. As discussed in the NODA, for the final rulemaking analysis, EPA has made changes to some of its co-benefit assumptions for subbituminous units with SCR and FGD controls. EPA is also using a newer version of EPA's IPM for the final rulemaking. Changes to the modeling assumptions can found in the IPM documentation in the rulemaking docket (see Documentation Summary for EPA Base Case 2004 (v.2.1.9) Using the Integrated Planning Model, EPA, October 2004).

Comment:

One commenter (OAR-2002-0056-5446) said there is considerable uncertainty over the extent of "co-benefit" reductions; however the current IPM assumptions fall within the likely range of co-benefit reductions.

Care must be taken when assuming co-benefit reductions as most reductions are calculated from analysis of the ICR emissions data which represent a limited snapshot of emissions from a few units taken over a very short period of time, with a limited number of coals. The data do not account for the wide variability of coals and process conditions encompassed by the full fleet of generator boilers. As stated previously the EPA must undertake some form of risk or probability analysis that considers variability in coal properties and unit performance to if it is to fully understand the implications of the proposed rule.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. The first phase cap is based on EPA modeling of the Hg co-benefits of SO_2 and NOx controls installed for compliance with the CAIR rulemaking. See final rule preamble for rationale and Chapter 7 of final CAMR RIA for discussion of emissions projections. As discussed in the NODA, for the final rulemaking analysis, EPA has made changes to some of its co-benefit assumptions for subbituminous units with SCR and FGD controls. EPA is also using a newer version of EPA's IPM for the final rulemaking. Changes to the modeling assumptions can found in the IPM documentation in the rulemaking docket (see Documentation Summary for EPA Base Case 2004 (v.2.1.9) Using the Integrated Planning Model, EPA, October 2004).

Comment:

One commenter (OAR-2002-0056-5510) stated that in regard to co-benefit reductions (or corresponding emission modification factors, EMF), the commenter noted that most of the estimates are based upon analysis of EPA's 1999 ICR data set. The commenter pointed out in comments dated May 14, 2004, the ICR emissions data represent a limited snapshot of emissions from a few units taken over a very short period of time, with a limited number of fuels. The data do not account for the wide variability of coals and process conditions encompassed by the full fleet of utility boilers. As a result, relatively little is known about long-term Hg emissions performance of the units that were tested or what may be achieved through a broader application of co-benefit technologies. Because of the lack of understanding associated with the level of Hg reductions that will be achieved through co-benefit reductions or future removal technologies, the commenter had recommended an alternative cap and trade program. This alternative would provide for co-benefit reductions in the first phase, coupled with an assessment of Hg emissions and performance characteristics of control technologies. An interim cap–effective in 2015–and coal type allocation adjustment factors would be based on this assessment. A final cap of 15 tons would be effective 2018.

The advantages to this proposal are: 1) it allows for the use of actual emissions data–as opposed to speculation about what may be achievable in the future–in the setting of the interim cap (i.e., it provides for a target that is known to be achievable); 2) it will provide for a mechanism that allows EPA to ensure a balance regulatory approach to Hg reductions (i.e., a rule that does not create regional disparities by advantaging one coal type over another). The commenter was particularly concerned about this issue because its members produce coal in every coal-producing region of the US, and represent coals of every rank.

Proposed allocation adjustment factors are based EPA's assessment of the relative ease with which Hg can be removed from different coal types; their intent is to "level the playing field." Because reductions associated with cobenefits are still not well understood, and Hg specific control technologies will not be available until the 2010 time frame, the allocation adjustment factors should not be set until EPA has a better sense of the capabilities of these technologies.

While Hg reductions will take place through the expanded use of co-benefit technology as required by CAIR, and promising Hg-specific technology is under development, it is premature to set a MACT, NSPS standard, cap, or emission allowance allocations because of the lack of reliable data on Hg emissions and the performance of control technology. It would be arbitrary and unreasonable to base an emissions standard on the hypothetical performance of unproven technology.

To the extent that EPA relies on EMFs for modeling purposes, those factors should be conservative enough to allow for the various sources of variability and uncertainty associated with co-benefit removal rates on different coal types. Where co-benefit reductions are the product of speculation within a range the commenter recommended a conservative estimation of

the EMF at the low end of the range; where evidence exists that co-benefit reductions are not being achieved, the commenter recommended an EMF of 1 (i.e., no co-benefit reductions). The commenter noted the results of a recent study conducted by the Energy and Environmental Research Center using a slipstream SCR unit at one lignite-fired power plant to determine the ability of new and aged catalyst to oxidize Hg. The results indicate "limited oxidation of Hg across the SCR catalyst when firing lignite coals" and that the sulfation of calcium and sodium ash deposits foul the catalyst rendering the SCIR–technology ineffective for NO_x control. An article describing the findings has been accepted for publication in Fuel Processing Technology. A copy of the "article in press" entitled, "SCR catalyst performance in flue gases derived from subbituminous and lignite coals" is attached (see e-docket text, Attachment 1).

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. The first phase cap is based on EPA modeling of the Hg co-benefits of SO_2 and NOx controls installed for compliance with the CAIR rulemaking. See final rule preamble for rationale and Chapter 7 of final CAMR RIA for discussion of emissions projections. As discussed in the NODA, for the final rulemaking analysis, EPA has made changes to some of its co-benefit assumptions for subbituminous units with SCR and FGD controls. EPA is also using a newer version of EPA's IPM for the final rulemaking. Changes to the modeling assumptions can found in the IPM documentation in the rulemaking docket (see Documentation Summary for EPA Base Case 2004 (v.2.1.9) Using the Integrated Planning Model, EPA, October 2004).

EPA projections of Hg co-benefits are based on 1999 Hg ICR emission test data and other more recent testing conducted by EPA, DOE, and industry participants. Overall the 1999 Hg ICR data revealed higher levels of Hg capture for bituminous coal-fired plants as compared to subbituminous and lignite coal-fired plants and a significant capture of ionic Hg in wet-FGD scrubbers. Additional Hg testing indicates that for bituminous coals SCR has the ability to convert elemental Hg to ionic Hg and thus allow easier capture in a wet-FGD scrubber. This understanding of Hg capture was incorporated into EPA modeling assumptions and is the basis for our projections of Hg co-benefits from installation of scrubbers and SCR under CAIR. (For further discussion see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005, in the docket).

Comment:

One commenter (OAR-2002-0056-5502) state that estimated emissions in 2010 after co-benefits of CAIR alone are realized remain in the range of 39-40 tons. Variations of the assumptions in EPMM that affect its estimate of co-benefits, accounting for new information from the commenter and other researchers, did not produce any significant change from the level of 39.9 tons that was reported in the earlier submittal.

Response:

EPA has examined the commenter's analysis in context of the final rulemaking. EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. The first phase cap is based on EPA modeling of the Hg co-benefits of SO_2 and NOx controls installed for compliance with the CAIR rulemaking. See final rule preamble for rationale and Chapter 7 of final CAMR RIA for discussion of modeling analysis.

Comment:

One commenter (OAR-2002-0056-5460) stated that EPA should not be concerned with the co-benefits of Hg reductions associated with implementation of the proposed CAIR. The commenter further stated that EPA is required to regulate power plant Hg emissions pursuant to Section 112 regardless of what CAIR may accomplish. The commenter added that, indeed, it is required to do so promptly, both under the plain language of the Clean Air Act and under a consent decree between EPA and the Natural Resources Defense Council (NRDC). See 42 U.S.C. § 112(c); OAR-2002-0056-3459 (NRDC comments) (describing consent decree). The commenter stated that given these requirements, and given EPA's own admission that CAIR may never become law, EPA should not continue to focus on the hypothetical consequences of CAIR.

Response:

EPA has examined the commenter's analysis in context of the final rulemaking. EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. The first phase cap is based on EPA modeling of the Hg co-benefits of SO_2 and NOx controls installed for compliance with the CAIR rulemaking. See final rule preamble for rationale and Chapter 7 of final CAMR RIA for discussion of modeling analysis.

Comment:

One commenter (OAR-2002-0056-5548) stated that CRA's 2004 EMF data (EEI data) better reflect current knowledge than EPA's, but should be modified as discussed below based on our more recent data. The commenter believed that EPA must augment and modify these EMFs using all available data that meet appropriate experimental quality criteria. In that context, the commenter reiterated their comment made on the initial proposal that much of the ICR Part III emissions data on which EPA has relied heavily does not meet reasonable tests of data quality and should be discounted, if only to meet EPA's stated objectives and obligations under the Data Quality Act.

CONSOL Energy Inc., in cooperation with the U.S. Department of Energy's National Energy Technology lab (DOE NETL), the Ohio Coal Development Office (OCDO), the Illinois Clean Coal Institute (ICCI), and the Electric Power Research Institute (EPRI), has conducted an extensive test program to measure Hg speciation and emissions on coal-fired boilers with wet

and dry Flue Gas Desulfurization (FGD) with and without Selective Catalytic Reduction (SCR) equipment. All of the units burned bituminous coal, and all but one of the wet-FGD units had an ESP for particulate control. Speciated measurements of Hg in the flue gas were made across the particulate control device as well as the FGD, and in the case of SCR-equipped units, ahead of the SCR. Appendix A provides detail on each unit, including the type of FGD, SCR and particulate collection device, and citations to more complete reports of the various tests. The Ontario Hydro Method (OHM) was used for all of these tests with the exception of the Hg removal across the ESP which was based on the Hg content of the ESP fly ash.

One important criterion for assessing the accuracy of Hg emission measurements is a material balance (notably lacking in the ICR Part III data), wherein the Hg content of the coal is measured and compared against the sum of the stack Hg emissions and the Hg contents of all process streams that contain Hg including such streams as the bottom ash, ESP ash, FGD solids, and mill reject pyrites. All of the data contained in Appendix A and summarized below have a material balance closure of ± 120 percent thus assuring a high degree of data quality.

Table 1 below lists each unit's emission control devices, the Hg removal across the ESP, the total (coal-to-stack) Hg removal and the average Hg removal for various emissions control configurations.

Table 1. Mercury Removal, Various Pollution Control Configurations

Bit Coal Plants	SCR	Part. Control Device	FGD	%Hg Removal across ESP	%Hg Removal Coal-to-Stack
1	Yes	FF	Lime Spray Dryer		87.3 ± 3.4
2	Yes	FF	Lime Spray Dryer		94.6 ± 0.3
Average percent Hg Removal for SCR/FF/FGD					**91.06 ± 5.2**
5	Yes	ESP	Limestone, in-situ Oxidation	17	85.8 ± 2.8
6	Yes	ESP	Limestone, in-situ Oxidation	24	88.2 ± 4.2
7	Yes	ESP	Limestone, in-situ Oxidation	6	83.6 ± 2.7
8	Yes	ESP	Mg-Lime, ex-situ Oxidation*		71.6 ± 5.2
9	Yes	ESP	Mg-Lime, Inhibited Oxidation		86.7 ± 2.8
10	Yes	ESP	Mg-Lime, Inhibited Oxidation		89.2 ± 3.6
11	Yes	Vent. Scrub	Mg-Lime Vent., Scrub. Inhib. Oxidation		85.1 ± 1.7
Average percent Hg Removal for SCR/CS-ESP/FGD				**15.7 ± 9.1**	**86.1 ± 2.1**
13	No	ESP	Limestone, in-situ Oxidation		48.7 ± 4.5
14	No	ESP	Limestone, in-situ Oxidation	23	74.6 ± 1.4
17	No	ESP	Mg-Lime, Nat. Oxidation	24.0 ± 11	66 ± 3
18	No	ESP	Limestone, in-situ Oxidation	7.0 ± 2.0	56.0 ± 6
19	No	ESP	Limestone, Nat. Oxidation	13.0 ± 2.0	72 ± 9
21	No	ESP	Limestone, Nat. Oxidation	9.0 ± 1.0	67 ± 3
22	No	ESP	Mg-Lime, Nat. Oxidation	11.0 ± 6.0	63 ± 4
Average % Hg Removal for CS-ESP/FGD				**14.5 ± 7.3**	**63.9 ± 9.0**
12	Yes	ESP		13	19.6 ± 20.7

*15 percent of flue gas is bypassed around FGD. Calculated percent Hg removal would be 84 percent.

This commenter and others stated that EPA must consider coal and process variability in any MACT, cap or allowance allocation determination. In each of the tests shown in Table 1,

four OHM tests were performed over a two to three day period. The variability evident from the test results over this short period of time is significant and must be considered by EPA. The standard deviation for SCR/FGD equipped units is 2.1 percent, indicating a relatively small variability among these measurements. The Hg removals from the FGD-only units have a standard deviation of 9.0 percent, indicating a greater variability among these units. Based on the test variability shown at each unit and the variability between units, the commenter believed that EPA must use a conservative EMF number to allow for the margin of variability inherent in both the Hg measurements and the performance of coal-fired units due to coal Hg content and process control. Therefore, the commenter recommended that EPA use EMF values reflecting the performance at the lower bound of a confidence interval calculated as one standard deviation about the average. Table 2 below compares the EMF's calculated in this manner from the data in Table 1 above to the EMF's provided by EPA in Table 5 of the NODA.

Table 2. EMF Comparisons

	EPA 2003 EMFs	CRA 2004 EMFs	EIA AE02004 EMFs	CONSOL Energy EMFs
Name of Control	Bit EMF	Bit EMF	Bit EMF	Bit EMF
PC/CS-ESP	0.64	0.65	0.64	0.93
PC/CS-ESP/FGD	0.34	0.40	0.34	0.45
PC/CS-ESP/SCR/FGD	0.10	0.15	0.10	0.16
PC/FF/SCR/FGD-Dry	N/A	N/A	N/A	0.14
PC/SCR/ESP	N/A	N/A	N/A	0.80

The commenter believed that the EMFs for the wet FGD units are similar, though somewhat greater than those proposed by CRA. One notable difference is the EMF for CS-ESP-only units. Because of the interest in Hg reduction as a co-benefit of NO_x and SO_x controls, there has been relatively little done to characterize emissions from this, the most common class of unit in use now. As the commenter noted in their June, 2004 comments on the initial proposal, these units were highly under-represented in the ICR Part III database. The commenter believed that EPA should revise the estimated EMF for these units to 0.93, based on the results presented here.

Response:

EPA has examined the commenter's analysis in context of the final rulemaking. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. The first phase cap is based on EPA modeling of the Hg co-benefits of SO_2 and NOx controls installed for compliance with the CAIR rulemaking. See final rule preamble for rationale and Chapter 7 of final CAMR RIA for discussion of emissions projections. As discussed in the NODA, for the final rulemaking analysis, EPA has made

changes to some of its co-benefit assumptions for subbituminous units with SCR and FGD controls. EPA is also using a newer version of EPA's IPM for the final rulemaking. Changes to the modeling assumptions can found in the IPM documentation in the rulemaking docket (see Documentation Summary for EPA Base Case 2004 (v.2.1.9) Using the Integrated Planning Model, EPA, October 2004).

EPA projections of Hg co-benefits are based on 1999 Hg ICR emission test data and other more recent testing conducted by EPA, DOE, and industry participants. Overall the 1999 Hg ICR data revealed higher levels of Hg capture for bituminous coal-fired plants as compared to subbituminous and lignite coal-fired plants and a significant capture of ionic Hg in wet-FGD scrubbers. Additional Hg testing indicates that for bituminous coals SCR has the ability to convert elemental Hg to ionic Hg and thus allow easier capture in a wet-FGD scrubber. This understanding of Hg capture was incorporated into EPA modeling assumptions and is the basis for our projections of Hg co-benefits from installation of scrubbers and SCR under CAIR. (For further discussion see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005, in the docket)

Comment:

One commenter (OAR-2002-0056-5548) stated that by definition, co-benefit reductions occur anyway as a result of control technologies installed to meet the CAIR. Hence, it is unnecessary to establish a cap to achieve Hg reductions through co-benefits.

As the commenter noted in their initial comments, because co-benefit Hg reductions will occur anyway, EPA's better course is to measure precisely what these co-benefits are, and use that information to set an interim cap in 2012, that would be effective in 2015. Setting the initial cap in 2012 allows EPA to quantify the precise amount of co-benefits reductions, and also allows EPA to dispense with its grossly unfair coal rank allowance allocation "adjustment" factors, since no such adjustments would be needed in the absence of an initial 2010 cap. As well, by 2012, EPA will be able to properly assess the performance of new Hg-specific control reduction technologies such as ACI to reduce Hg emissions across all coal ranks. The commenter was confident that the technology will show that roughly equal removal levels can be achieved across all coal ranks. Hence, EPA would not be justified in establishing allowance allocation adjustment factors for any subsequent cap.

The commenter noted that the EEI's modeled "Alternative Hg Trading" scenario outlined in the NODA generally follows this approach by establishing no first phase co-benefits cap, and setting an initial firm cap (24 TPY) in 2015. Because the EEI proposal would allow banking of early reduction credits above co-benefits, the eligibility of actions that qualify for early reduction credit would need to be defined. However, this early reduction and banking system is wholly discretionary, and consequently there is no need to adjust allocation of allowances by coal rank to implement it since there is no specific obligation by any individual source to reduce Hg emissions to a pre-determined level.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. The cap-and-trade program will include a provision for banking. See final rule preamble and Chapter 5 comment responses for further discussion of banking. EPA is not including a provision for early reduction credits in the final rulemaking. See Chapter 5 response to comments for further discussion of ERCs.

8. More recent test data on subbituminous coal-fired units equipped with SCR indicate that SCR does not enhance the oxidation of Hg^0 on such coals and, thus, does not provide for additional capture in a wet scrubber (OAR-2002-0056-1268, -1270). Based on these data, EPA is considering revising the emission modification factor (EMF) for subbituminous coal-fired units equipped with SCR and wet FGD in the IPM model. EPA recommends use of the EMF control combination before an SCR is added (i.e., ascribe no additional control due to the addition of the SCF). EPA requests comments on these proposed changes: for CS-ESP/SCR/FGD, use CS-ESP/FGD (0.84); for FF/SCR/FGD, use FF/FGD (0.27); and for HS-ESP/SCR/FGD, use HS-ESP/FGD (0.80). EPA also requests comment on the appropriateness of using other test data (DOE and EPRI tests) for EMF development and asks commenters to submit any relevant data.

Comment:

One commenter (OAR-2002-0056-5475) mentioned that EPA may rely on information gleaned from reports that were not available for public review prior to the end of the comment period. The commenter recommends that any reports, or studies, relied upon in making determinations relevant to the Hg rule be made available for public review.

Response:

EPA projections of Hg co-benefits are based on 1999 Hg ICR emission test data and other more recent testing conducted by EPA, DOE, and industry participants. This testing is summarized in reports by EPA, DOE and others and are available on EPA's website. In addition a comprehensive summary of this test was prepared by EPA's Office of Research and Development (ORD) assessment and made available in the docket at time of the proposal. available in For the final rule ORD has prepared an updated assessment (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005, in the docket).

Comment:

One commenter (OAR-2002-0056-5482) stated that in August 2003, a pilot-scale SCR reactor was installed at a Fort Union mine-mouth lignite-fired EGU located in North Dakota. The study was conducted by the Energy and Environmental Research Center (EERC) to

determine the ability of new and aged catalyst to oxidize Hg at full-scale EGUs. The results indicate that SCR technology was not effective in oxidizing Hg and that the sulfation of calcium and sodium ash deposits foul the catalyst rendering the SCR technology ineffective for NO_x control.

An article describing the findings has been accepted for publication in Fuel Processing Technology. A copy of the "article in press" entitled, "SCR Catalyst Performance in Flue Gases Derived from Subbituminous and Lignite Coals" can be downloaded from the EERC ftp site: ftp://ftp.undeerc.orglbenson/ .

The article is also available online via Science Direct in the "Articles in Press" section for the following title: http://authors.elsevier.com/sd/article/S0378382004001870 .

Response:

EPA has examined the commenter's analysis in context of the final rulemaking. EPA's modeling Hg co-benefit assumptions already assume that SCR does not enhance Hg control for lignite plants.

Comment:

One commenter (OAR-2002-0056-5482) noted that Table 5 of the NODA, "Hg Removal Assumptions for Pollution Control Equipment," identifies lignite EMF factors for various EGU pollution control configurations. As noted in the above EERC study and EPA's acknowledgment of a lack of SCR elemental Hg reduction co-benefits for subbituminous coal (similar to Fort Union lignite), the this commenter recommends an EMF factor designation of 1.0 or "NA" (not applicable) for all Fort Union EGU pollution control configurations employing SCR.

As previously noted, elemental Hg is the predominant form of Fort Union Hg emissions and conventional air pollution control equipment provides little or no incidental removal. An important factor impacting EMF values is the high variability of Hg and important species such as chloride and alkali. The interplay of the chemical factors coupled with EGU operation variations would not justify an EMF factor of less than 1.0. The EMF factor of 0.56 for configuration PC/CS-ESP/FGD is not representative of Fort Union lignite EGU emissions.

The commenter recommends an EMF factor of 1.0 be employed for PC/CS-ESP/FGD, similar to the PC/CS-ESP, FF/FGD-Dry and PC/FF configurations.

No Fort Union configurations of PC/CS-ESP/FGD-Dry are known. The commenter recommends an EMF factor designation of "NA."

The commenter also recommends an EMF factor of "NA" for all PC/HS-ESP pollution control configurations since the technology is not applicable or utilized by Fort Union EGUs.

Response:

EPA projections of Hg co-benefits are based on 1999 Hg ICR emission test data and other more recent testing conducted by EPA, DOE, and industry participants. EPA believes the lignite factors used for final rulemaking analysis are supported by ICR test data. (For further discussion see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005, in the docket.)

Comment:

One commenter (OAR-2002-0056-5446) stated that in order to provide a level playing field any "cap-and-trade" type regulatory approach must include appropriate allocation factors. The factors currently proposed by the EPA, 1.0 for bituminous, 1.25 for subbituminous and 3.0 for lignite do not adequately address this issue. Even the EPA states that these factors are only "directionally correct," this is a completely inadequate basis for setting a regulatory standard.

Furthermore, assessment of the EMFs used in the different models indicates that these allocation factors are likely to be inadequate. For the most common generating configuration (PC/CS-ESP representing approximately 59 percent of generating capacity) the EPA and EIA assume a 36 percent Hg reduction for bituminous coal and a 3 percent reduction for subbituminous coal, CRA assumes a 35 percent reduction for bituminous coal and a 20 percent reduction for sub-bituminous coal. For the second most common configuration (PC/CS-ESP/FGD representing approx 16 percent of capacity) the EPA and EIA assume a 66 percent Hg reduction for bituminous coal, and a 16 percent and 27 percent reduction respectively for subbituminous coal. Even when adjusted for average Hg content of bituminous and subbituminous coals these reduction factors imply that the allocation factor for subbituminous coal should be higher that the 1.25 proposed by the EPA.

However given the wide range of uncertainty in the reduction factors (e.g., a reduction factor of between 3 percent and 20 percent for PC/CS-ESP with sub-bituminous coal) basing allocation factors on the relative proportions of elemental Hg produced by the different coal ranks is likely to be a more robust approach.

Because the amount of elemental Hg produced effectively reflects the difficulty of control, factors based on elemental Hg content are more likely to result in an even distribution of the compliance burden between coal ranks in the long term. However, because plant configuration also affects Hg capture and as subbituminous coal is typically burned in plant configurations that produce little co-benefit capture (e.g., plants with dry scrubbers) a subbituminous factor based purely on elemental Hg content will be inadequate to avoid fuel switching in the short term. As per our original comments, factors of 1.0 for bituminous, 1.9 for subbituminous and 2.95 for lignite, as proposed by the industry majority during the CAAAC process, appear to be the most appropriate. These factors have been calculated from the floors developed by industry majority position, which included representatives from the unions, the major coal producing regions and a large proportion of the electric utility industry.

Testing to date indicates that the presence of an SCR does not enhance Hg removal from sub-bituminous coals. Therefore, the commenter strongly supports the EPA's recommendation that the EMF assume that the presence of an SCR provides no additional Hg control for sub-bituminous coals.

Response:

As discussed in the Chapter 5, section 5.6.1, EPA is finalizing coal adjustment factors for the purpose of establishing state emission budgets of 1.0 for bituminous coals, 1.25 for subbituminous coals, and 3.0 for lignite coals. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Indian Country Emissions Budgets, EPA, March 2005.

Comment:

One commenter (OAR-2002-0056-5510) stated that EPA should draw upon whatever data is available, provided appropriate data quality controls have been applied. In this regard, however, the commenter again drew attention to the problems with EPA's use of the ICR Part III data set, as outlined in their May 14, 2004 comments. In particular, the commenter noted their concerns associated with EPA's use of short-term test data. Great care should be taken to account for the uncertainty and variability in coal quality, unit operation, and to the variable performance of pollution control devices. The commenter does not believe that the large degree of uncertainty incorporated by these variables can be adequately attenuated through short term tests performed on a limited number of units, coal types, plant configurations and operating conditions. To resolve these problems, EPA should institute a comprehensive test program, as elsewhere described in these comments.

Response:

EPA has used the best data were possible in developing its analysis for the final rulemaking. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter's (OAR-2002-0056-5492) question: EPA is considering making three changes to the subbituminous coal EMF used in the IPM: for CS-ESP/SCR/FGD use CS-ESP/FGD (.84); for FF/CR/FGD use FF/FGD (.27); and for HS-ESP/SCR/FGD use HS-ESP/FGD (.8). EPA is seeking comments on these proposed changes.

In the NODA, EPA cites two literature references: OAR-2002-0056-1268 and OAR-2002-0056-1270. These two references cite the same source data, based on a single test. The two reports are using information developed and reported in an EPRI report. In the report,

EPRI and their contractor point out several exceptions to standard flue gas sampling procedures. First, the samples are single point and are not a full or even a partial traverse of the duct. Flue gas stratification could mean that the observations are not representative of the entire flue gas stream. Second, only duplicate flue gas Hg samples were obtained. In all EPA methods, samples are obtained in triplicate. The authors state that ". . . the data set presented here is small, so the reader should exercise caution in extrapolating the results. . . ."

In addition, the authors state that "an increase in oxidized Hg from 8 percent to 18 percent (occurred) across the SCR." They go on further to state "Consequently, Hg capture across the ESP increased from 60 percent to 78 percent as a result of SCR operation." The authors statements in the cited reports do not support EPA's conclusion that "SCR does not enhance the oxidation of Hg." The commenter respectfully suggested that the proposed changes are unwarranted based on the data submitted by EPA.

Question: EPA is seeking comment on the appropriateness of using other test data for EPM development and requests commenters submit any test data that may be relevant.

The Department of Energy has operated a COHPAC system for Hg removal at the Southern Company Gaston Station which fired a low sulfur bituminous coal for about one year. At an injection concentration of 0.55 lb/mmacf and using 2.7 denier bags, over a four-month period the average Hg removal was 86 percent. During shorter-term tests using higher denier bags, 7 denier, it was possible to achieve greater than 90 percent Hg removal. The weekly average Hg removals observed at the Gaston site are presented in e-docket text.

In addition to the COHPAC tests, additional tests were conducted using activated carbon injection on CS-ESP and SCR/dry FGD units firing subbituminous coals. For example, at the subbituminous coal fired Sunflower Electrics Holcomb Station which is equipped with a SCR/dry FGD system, over 90 percent Hg reduction was achieved for the entire 4-week test period.

In addition, there have been tests at Pleasant Prairie Station that fires a subbituminous coal and is equipped with a CS-ESP. At an injection rate of 11 lb/mmacf, 73 percent Hg removal was reported.

Additional tests were completed on both bituminous and subbituminous coals. There are a number of publications listed at the following web address: www.adaes.com under "Publications" on the tool bar. There have been at least four full-scale evaluations of ACI on PRB coal fired units (Holcomb Arapahoe (two tests), Meramec) and four tests on lignite fired boilers(Antelope Valley, Stanton 1, M.R. Young, and Monticello).

Response:

EPA appreciates the commenter's input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's

Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5502) referenced co-benefits and agreed with EPA's proposal to assign no co-benefit to the addition of an SCR at a site with an SO_2 control that is burning a western fuel. This is generally supported by the small, but growing, body of data available to date. These data are provided in the detailed comments, as are suggested EMFs for a number of fuel/air pollution control configurations.

Power plants firing a bituminous coal can expect to experience oxidized Hg fractions in the flue gas entering the FGD that range from 75-90 percent–i.e., high but not necessarily always in the 90 percent range. There does not appear to be a significant increase in Hg oxidation for PRB coals, and potential low-chloride bituminous coals.

Response:

EPA projections of Hg co-benefits are based on 1999 Hg ICR emission test data and other more recent testing conducted by EPA, DOE, and industry participants. EPA believes the factors used for final rulemaking analysis are supported by test data. EPA's Hg co-benefit assumptions can found in the IPM documentation in the rulemaking docket (see Documentation Summary for EPA Base Case 2004 (v.2.1.9) Using the Integrated Planning Model, EPA, October 2004). The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5535) said that in conducting the various modeling exercises, different stakeholders used different emission modification factors (EMF) to calculate the Hg co-control benefits of different NO_x and SO_2 controls. The EPA requests comments on what EMF are appropriate. As shown in Table 5 of the NODA, there are differences in EMF the agency has developed and those used by Charles River Associates (CRA) for industry stakeholder modeling. The commenter noted that the EMF used by CRA are consistently lower than the EMF developed by EPA, that is, they result in less co-control of Hg emissions than assumed by EPA. The result, not surprisingly, is that industry stakeholders estimate that Hg emissions will be higher after implementation of CAIR requirements than EPA has stated. Because EPA has proposed to establish the first phase of its pollution trading scheme to reflect reductions achieved as a co-benefit of CAIR, the effect of industry's suggested EMF changes would be to inflate the initial Hg cap, making it easier to meet without significant control, or making it easier for companies to bank allowances for future use.

With the exception of new data on the effects of SCR on Hg oxidation when

subbituminous coals are fired, the commenter saw no new information in the other commenter's remarks that should lead EPA to change the EMF in the IPM. EPA developed the existing EMF after analyzing the extensive ICR data set. In contrast, there are no new analyses of Hg co-control presented by other commenters. Thus, EPA need not revise its EMF, despite the desire of industry stakeholders to raise the first phase Hg cap. With respect to EPA's intention to revise the EMF associated with the use of SCR with subbituminous coals, the agency does not provide sufficient information for us to comment on whether this is a legitimate action. The agency merely refers to "more recent test data." EPA must submit to the docket all of the test data along with the agency's analysis of such test data in support of any such changes to the EMF. Revising the EMF associated with the use of SCR with subbituminous coals without making such data and analysis publicly available would be arbitrary.

Fourth, EPA also mentions Hg speciation in the context of conducting economic modeling with the IPM. With respect to the use of different speciation profiles in the IPM, EPA notes that the national estimate of emissions of the three forms of Hg is Hg^0–54 percent, Hg^{+2}–43 percent, and Hg^p–3 percent. The agency states that plant-specific estimates based on these data were used in the IPM modeling activities. The IPM should not be revised with respect to Hg speciation. To the extent that different speciation profiles have been estimated for different coal types and control device configurations, these data have already been incorporated into the IPM through the use of EMF. The EMF are average control levels that are calculated from average Hg and chlorine levels in coal and averages of test data, so the use of average speciation profiles in the IPM model is appropriate. The commenter noted however, that EPA could and should improve the speciation profiles used in deposition modeling, as discussed above.

Response:

EPA projections of Hg co-benefits are based on 1999 Hg ICR emission test data and other more recent testing conducted by EPA, DOE, and industry participants. This testing is summarized in reports by EPA, DOE and others and are available on EPA's website. In addition a comprehensive summary of this test was prepared by EPA's Office of Research and Development (ORD) assessment and made available in the docket at time of the proposal. For the final rule ORD has prepared an updated assessment (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005, in the docket). With regard to speciated profiles, IPM modeling includes only total Hg emissions projections as output. EPA than post-processes IPM unit level results to determine the speciated form of Hg at the unit level. This information is than used in deposition modeling. The determination on speciated emissions is based on 1999 ICR data.

Comment:

One commenter (OAR-2002-0056-5548) noted that EPA was considering revising the EMFs for subbituminous coal-fired units equipped with SCR and wet FGD. After reviewing the literature cited by EPA to support this change and discussing the supporting data with EPA R&D and EPRI, the commenter did not believe that the available data support the proposed changes.

First, there are not two independent literature sources as cited by EPA in the NODA. These two papers simply report the same information from a single set of measurements on a PRB coal-fired unit, equipped with an SCR, a CS-ESP, originally reported in EPRI Report 1005400 dated December 2002. Notably, although EPA proposes to use these data to modify the EMFs for FGD-equipped units, the one test cited in these two reports was done on a unit with no FGD. It also is noteworthy that the report states, "Caution is urged in drawing conclusions from this limited set of data. The results are based on short-term tests that might be misleading due to the potential for substantial variation in total and speciated mercury concentration." Moreover, the results do show a significant increase in oxidized Hg across the SCR (from 8 percent to 18 percent), and a total Hg removal (78 percent) for a SCR-CESP unit. The commenter believed that the proper manner to evaluate the effect of SCR operations is the impact on total Hg removal. These results, the only ones that EPA cites, indicate that a boiler equipped with an SCR-CS ESP combination firing a subbituminous coal can achieve a 78 percent Hg reduction. One of the cited references states "Consequently, mercury capture across the ESP increased from 60 percent to 78 percent as a result of SCR operation." The EPA, DOE, and EPRI authors ascribe a significant increase in Hg removal to the SCR operation. The cited literature does not support EPA's contention that they should "...ascribe no additional control due to the addition of the SCR..." Rather the cited papers state that the operation of the SCR improved total Hg capture.

The commenter added that in addition to the papers cited by EPA in the NODA, there was a joint study conducted by EPA R&D and EPRI at the Texas Genco WA Parish Station. (The final report is in draft.) The Parish Station burns subbituminous coal and is equipped with an SCR/FF/wet FGD air pollution control system. This system achieved 64 percent Hg control with the FF/wet FGD in operation. With the SCR/FF/wet-FF/wet-FGD in operation, the Hg removal increased to 79 percent. Again the operation of the SCR significantly increased the co-benefit Hg removal of the air pollution control system.

In the commenter's opinion the literature provided no supporting information for the proposed changes to the EMFs. Instead, it indicates that the EMF for subbituminous coal-fired units equipped with CS-ESP/SCR/FGD should be 0.2, and for units equipped with SCR/FF/FGD should be between 0.2 and 0.3.

Response:

EPA projections of Hg co-benefits are based on 1999 Hg ICR emission test data and other more recent testing conducted by EPA, DOE, and industry participants. EPA has assumed for the final rulemaking analysis that for subbituninous-fired units that SCR has the no ability to convert elemental Hg to ionic Hg and thus allow easier capture in a wet-FGD scrubber. EPA is thus using the emission modification factors for CS-ESP/SCR/FGD, use CS-ESP/FGD (0.84); for FF/SCR/FGD, use FF/FGD (0.27); and for HS-ESP/SCR/FGD, use HS-ESP/FGD (0.80). EPA EPA's Hg co-benefit assumptions can found in the IPM documentation in the rulemaking docket (see Documentation Summary for EPA Base Case 2004 (v.2.1.9) Using the Integrated Planning Model, EPA, October 2004). The Agency's position on the state of Hg technology is contained in

the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5497) stated that the different levels of Hg co-benefits predicted from implementation of the CAIR rule are hardly surprising. The 1999 Information Collection Request (ICR) stack testing results, which serve as the basis for most emission modification factors, showed highly variable Hg removals in plants equipped with the same control equipment. In addition, predicting the level of Hg co-benefits resulting from the CAIR rule requires one to estimate the effects of SCRs on Hg removal. Mercury testing of SCRs is limited and questions remain about a number of factors that may affect the amount of elemental Hg that is converted to ionic Hg in an SCR. As a result of these uncertainties, it is impossible to predict the true co-benefits that will be achieved from implementation of the CAIR rule. As was described in the preceding response, the commenter believed that instead of trying to set a "hard" cap based on co-benefits in 2010. EPA would be better served by imposing a "soft" cap and commencing trading
in 2015.

The commenter agreed with the Electric Power Research Institute (EPRI) that many of the EMFs should be revised, in most cases very slightly, to reflect additional information that has been received since EPA last ran its IPM model. For example, for bituminous coals, the commenter recommended these changes:

- CS-ESP/wet FGD: Revise EPA's EMF from 0.34 to 0.40 because six additional test results have doubled the database.

- SCR/CS-ESP/wet FGD: Revise EPA's EMF from 0.10 to 0.15 based upon ICR measurements and recent SCR/FGD co-benefits tests.

For other configurations (e.g., SCR/FF/wet FGD and SCR/FF/dry FGD) the commenter believed that no change is justified. A complete list of our recommendations is attached.

Response:

EPA is finalizing a cap-and-trade approach under section 111. EPA is establishing a phase I cap of 38 tons in 2010 and phase II cap of 15 tons in 2018. See final rule preamble for rationale. EPA projections of Hg co-benefits are based on 1999 Hg ICR emission test data and other more recent testing conducted by EPA, DOE, and industry participants. EPA EPA's Hg co-benefit assumptions can found in the IPM documentation in the rulemaking docket (see Documentation Summary for EPA Base Case 2004 (v.2.1.9) Using the Integrated Planning Model, EPA, October 2004). The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from

Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5497) stated that they believed that there were inadequate data to assign any measurable or reproducible level of SCR co-benefits for either wet or dry scrubbers. Two independent sources of data support this conclusion.

First, EPRI has synthesized the increase in oxidized Hg across SCR equipment at 18 sites. Of the 18 sites, three fire Powder River Basin ("PRB") coal and exhibit an increase in oxidized Hg between effectively zero (Site S9) to 19 percent (Site 1). These data suggest there is effectively no Hg oxidation across the SCR catalyst. The commenter did not think that the anomalous Site 1 unit–a cyclone boiler–is representative of the boiler design and characteristics of the boiler population in this nation. That boiler has relatively low particulate matter loading, elevated NO_x level entering the SCR reactor, and the lowest space velocity (e.g., most generous catalyst volume) of any of the tested units. Cyclone boilers comprise less than 5 percent of the boiler population. The other units are representative of boiler design and catalyst space velocity. While they suggest a 3-4 percent increase in Hg oxidation with PRB coal, this is within the "noise" of the measurement systems.

The second set of data that supports this conclusion is the measurement of increased Hg removal across a wet scrubber due to SCR. Of the sites reported, only Site 11 is equipped with wet scrubber. The use of SCR induces an 11 percent increase in the removal of Hg by a wet scrubber. Site 11 is equipped with a fabric filter that precedes the wet scrubber, and EPRI reports that much of the Hg oxidation occurs across the fabric filter, unrelated to the SCR. Consequently, it appears that much of the 11 percent increase in Hg removal is due to the fabric filter, and not the SCR.

For these reasons, and because the data are sparse and preliminary, the commenter suggested that zero co-benefits be assigned to the role of SCR on PRB and other subbituminous coals.

Response:

EPA has assumed for the final rulemaking analysis that for subbituninous-fired units that SCR has the no ability to convert elemental Hg to ionic Hg and thus allow easier capture in a wet-FGD scrubber. EPA EPA's Hg co-benefit assumptions can found in the IPM documentation in the rulemaking docket (see Documentation Summary for EPA Base Case 2004 (v.2.1.9) Using the Integrated Planning Model, EPA, October 2004).

Comment:

One commenter (OAR-2002-0056-5411) stated that their results indicated that the EMFs are not related to coal rank, but do vary with coal age. The consistent relationship between the

EMFs and the geologic age of coal, coupled with simple criteria that definitively establish the age of coal, provide a scientifically justified and practical basis to subcategorize coal for regulation of Hg emissions.

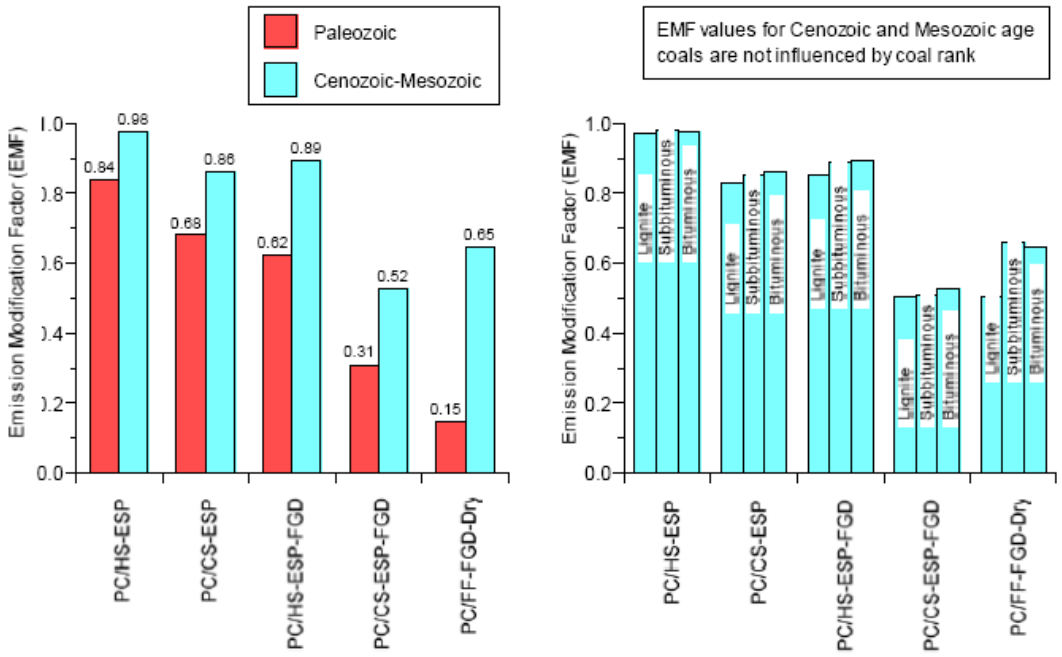
The commenter stated that commercial U.S. coal was formed during two, substantially different geologic ages, and can be broadly grouped as older Paleozoic coal, and younger Mesozoic/Cenozoic coal. The mutually exclusive geographic occurrence of Paleozoic coal and Mesozoic/Cenozoic coal is significant. Unlike coal rank, which varies locally, with ASTM standard vintage, and with assay precision, geologic age can be unambiguously determined based on coal origin location. Moreover, the origin location of coal shipments to units ≥50 MW is publicly reported; if regulation of units as small as 25 MW is required, determining the coal origin location is clearly less burdensome than representative sampling for coal rank assays. Finally, a precise coal origin location is not required to establish geologic age. Indeed, the "state-of-origin" reported on FERC form 423 is sufficient to establish geologic age for current coal production.

The commenter also stated that in the unlikely event that the age of a coal shipment is disputed, the 200 million year interval between Paleozoic coal and Mesozoic/Cenozoic coal is significant. Ubiquitous pollen from angiosperms (flowering plants), as well as certain terpene resins, are found in Cretaceous and Paleogene coal, but absent from Paleozoic coal. Consequently, if shipment receipts or transportation records prove insufficient, palynological or geochemical assays can definitively settle such disputes.

The commenter calculated Emission Modification Factors (EMFs) for five of the 12 emission control technologies listed in Table 5 of the December 1, 2005 Federal Register Notice (69 FR p. 69871). Their calculation method is described in their docket comment (Appendix B) together with the tabulated data used for this calculation. The results are illustrated in the figure below, which shows greater Hg capture for units burning Paleozoic coal than for units burning Mesozoic/Cenozoic coal. Note that all U.S. Paleozoic age coal is bituminous or anthracite rank, whereas the rank of U.S. Mesozoic/Cenozoic age coal varies. Importantly, the figure below also shows that the EMF does not vary with coal rank, but does vary with coal age.

The commenter added that the EMFs that they calculated are not directly comparable to those shown in Table 5 of the NODA. Nonetheless, with two minor exceptions, our EMFs are generally closest to the CRA 2004 values listed in the table. The first exception is for the relatively small HS-ESP/FGD technology class, where our EMF values are more similar to the EPA and EIA values. Secondly, our EMFs for the important CS-ESP/FGD technology class suggest slightly less Hg capture for this class than any of corresponding EMFs in the table.

U.S. Cenozoic/Mesozoic age coal has greater fractional mercury emissions (EMF values) than U.S. Paleozoic age coal, when burned in units equipped with conventional emission control technologies; this difference is not related to coal rank.



Notes, PC: pulverized coal; HS-ESP: hot-side electrostatic precipitator; CS-ESP: cold side electrostatic precipitator; HS-ESP-FGD: hot-side electrostatic precipitator with wet Flue Gas Desulphurization; FF-FGD-Dry: Fabric Filter and spray dry adsorption Flue Gas Desulphurization.

More than 25,800 ICR records were used to calculate the EMF values presented in the figure above; ~5,500 ICR coal assay data records where the location origin was not reported were ignored, as were ~3,300 records corresponding to blended coals. The tonnage weighted EMFs calculated for this comment (Table 3) indicate the fractional emissions expected if all U.S. coal were burned in each technology class, rather than the coals that are currently burned. Although this approach is neutral with respect to fuel switching, it may overestimate Hg emissions for some units that burn blended coal. The omission of blended coals is likely to have slightly decreased our EMF's for CESP/FGD units and PC/FF-FGD-Dry units. This effect can be demonstrated for these technologies using the equations listed in Table Bl (see OAR-2002-0056-5411), which predict net improved Hg capture for blends containing both high and low chlorine coal. The equations show predicted Hg capture substantially increases as chlorine content approaches 500 ppm, but only modestly rises above 1000 ppm chlorine. Thus, blending to optimum chlorine content between 500 and 1000 ppm, should result in a net reduction of Hg emissions.

A potentially more significant limitation of the EMFs presented in this comment is equally applicable to those listed in Table 5 of the NODA. Current FF/FGD-Dry technology is limited to low-sulfur coal. Fortunately, excluding the ~30 percent of U.S. coal production that

contains more than 1 lb sulfur/10^6 Btu, does not significantly change the our calculated EMFs for FF-FGD-Dry technology; respective EMFs for Paleozoic and Mesozoic/Cenozoic coal are 0.13 and 0.64, for low-sulfur coal burned in units with FF/FGD-Dry technology. However, assuming a 1 lb sulfur /10^6 Btu limit, FF/FGD-Dry technology is only applicable to ~25 percent of northern lignite, and hardly any Texas lignite, or coal from Ohio and Northern Pennsylvania - all of these areas produce relatively high Hg coal. Consequently, one of the best existing Hg reduction technologies is not appropriate for many coals with the highest Hg contents.

Due to time constraints, the commenter noted without comment the remarkably improved Hg capture suggested by the EMFs listed in Table 5 for units with SCR technology compared to those without SCR. For the same reason, the commenter had not considered Indonesian, Venezuelan, Columbian, Polish, or Alaskan coal, although these calculations are comparatively straightforward. Evaluation of potential coal supplies from countries not included in the ICR is more problematic; assay data from the USGS international coal data base might be useful for this purpose.

Response:

For the final rulemaking, EPA is using Hg emission modification factors based on coal rank. We believe this approach is consistent with our understanding of Hg control. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005). EPA EPA's Hg co-benefit assumptions can found in the IPM documentation in the rulemaking docket (see Documentation Summary for EPA Base Case 2004 (v.2.1.9) Using the Integrated Planning Model, EPA, October 2004).

B. Issues of Hg Speciation

General Comments Concerning Issues of Mercury Speciation

Comment:

One commenter (OAR-2002-0056-5460) stated that the NODA reveals an undue concern for alleged uncertainties concerning Hg speciation and the relative contribution of domestic power plants to global Hg emissions. The commenter further stated that EPA need not and should not delay regulation of domestic power plant Hg emissions until those alleged uncertainties are resolved. According to the commenter, rather, to the extent uncertainties exist concerning such topics as Hg speciation, transport, deposition and exposure, those uncertainties provide a basis for imposing stricter protections so as to ensure an adequate margin of safety. The commenter stated that no other approach is consistent with the preventive and precautionary purposes of the CAA.

The commenter (OAR-2002-0056-5460) also stated that developing a Hg speciation

profile is not relevant to setting a proper MACT floor pursuant to CAA section 112. The commenter added that, rather, by statute that floor is to be based on the average of actual emissions achieved by the top 12 percent of the coal-fired power plants for which EPA has data. The commenter added that, equally important, developing a speciation profile will not cure the legal defects in EPA's proposed section 111 approach.

The commenter stated that a speciation profile might be relevant to certain aspects of the beyond-the-floor analysis required by section 112, but EPA cannot and should not use either the fact of speciation, or uncertainty about the nature of such speciation, as a basis for concluding that section 112 no longer applies. The commenter further stated that, indeed, EPA's December 2000 determination that it was necessary and appropriate to regulate Hg emissions from power plants was not limited to particular species of Hg, and no basis exists for EPA to revisit or revise that determination now.

Response:

EPA is not delaying regulation of U.S. utility units until all uncertainties are resolved. However, we believe that these uncertainties do factor into the approach that should be taken in such regulation. We believe that the cap-and-trade approach being finalized adequately accounts for the uncertainties.

Comment:

One commenter (OAR-2002-0056-5535) stated that the Agency's interest in speciation profiles and how they relate to Hg control, fate and transport, and ultimately human exposure raises the question of whether the Agency is contemplating basing emission rates or trading schemes on the level of different Hg species emitted. The overall impression left by this line of inquiry is that the Agency is suggesting that only oxidized Hg emissions from power plant need to be controlled. This is clearly inappropriate and arbitrary – elemental Hg is no less important than oxidized Hg in terms of the environmental and public health impacts in the U.S. To imply that elemental Hg does not contribute to Hg exposure in the U.S. is incorrect, because elemental Hg is eventually oxidized and deposited. This deposition can occur on the east coast of the U.S. as a result of emissions from a boiler located in the western U.S., or it may occur in the western U.S. from elemental Hg emissions circling the globe. Comments submitted to the EPA by a consortium of scientists convened by the Hubbard Brook Research Foundation (HBRF) emphasize that elemental Hg can be rapidly converted to oxidized Hg and deposited locally or regionally. This process is known to occur after polar sunrises in the Arctic and Antarctic atmosphere and in the marine boundary layer in the presence of marine aerosols. Furthermore, emissions of oxidants from utilities and other high-temperature sources provide ample reactants for oxidizing elemental Hg. New research shows that dry deposition of elemental Hg, uptake of elemental Hg by the forest canopy and subsequent litter fall can provide more than twice as much Hg to a watershed than wet deposition. Moreover elemental Hg can be converted to reactive gaseous Hg (RGM or oxidized Hg) at a tree's leaf surface, thereby enhancing the deposition of elemental Hg at the local and regional scale and reducing long range transport.

Consequently, there is ample evidence that emissions of elemental Hg must be reduced in conjunction with oxidized Hg emissions.

In addition, EPA cannot even entertain the notion that elemental Hg emissions need not be controlled from U.S. power plants and maintain an ounce of credibility in global Hg protocol discussions. One of Administrator Leavitt's "guiding principles" recognizes that Hg is a global issue and asks what opportunities there are to reduce Hg emissions worldwide. The opportunities to reduce global emissions (and their subsequent impacts in the U.S.) will only arise if the U.S. is serious about reducing total Hg emissions from coal-fired power plants.

Comment:

One commenter (OAR-2002-0056-5464) noted that the NODA includes a discussion about speciation. It is unclear to them what EPA means by this discussion. If EPA's intention is to regulate by species, it is important to note that the workgroup discussed that idea briefly and rejected it as an unworkable solution. Further, although some companies have indicated that Hg emitted as oxidized all becomes elemental Hg in the plume as it exits the stack, this is counter to the vast research on Hg's behavior in the atmosphere. The key point here is that this industry finding is too preliminary, is within the error of measurements, and has had inconsistent results in different power plant plumes. Even if this one reaction among many is confirmed in later studies, this work needs to be interpreted in the context of many other atmospheric reactions of Hg whose net effect and direction tendency is just the opposite: conversion of elemental Hg into oxidized Hg. Oxidized Hg deposits locally and regionally, and a MACT that requires ALL power plants to substantially reduce emissions significantly (80-90 percent) would protect against hot spots.

The discussion about speciation relates to the atmospheric fate and transport of Hg emissions. Regardless of where emissions originate, in a world where international transport is becoming an increasing public health concern, there is no justification for this country turning its back on our contributions to transboundary pollution. This commenter believed the U.S. should show leadership by controlling Hg emitted here, regardless of where and how emissions travel.

Response:

EPA is showing leadership through issuance of this first-ever regulation limiting Hg emissions from coal-fired power plants. We agree that, at this time, it is inappropriate to regulate Hg emissions by species and, therefore, have structured the final rule on a total Hg basis.

Comment:

One commenter (OAR-2002-0056-5559) stated that the 1999 ICR data is the most comprehensive body of Hg speciation data available that was developed through consistent and standard measurement methods. The commenter stated that EPA should rely on the ICR data as

the primary basis for evaluating existing Hg control measures. The additional body of Hg emission testing conducted since 1999 by researchers and industry can be used to augment the ICR data but in doing so EPA needs to account for differences in testing methods and conditions.

Response:

EPA concurs with the commenter.

Comment:

One commenter (OAR-2002-0056-5474) stated that it fully supports using different multipliers for the different coal ranks for the reasons stated above, but is concerned that the multiplier will be determined by using the coal or coals that a unit burned in 1999 rather than the coal a unit is actually burning at the time the rules are finalized. That approach is inequitable and grossly unfair to any unit that has switched from a higher to lower rank coal since 1999. This commenter has two units that made the decision in 2001 to switch from bituminous to subbituminous coal, to reduce NO_x emissions to comply with new anticipated regulatory requirements. The engineering and design work needed to make the equipment and operational changes necessary for such a switch was started in late 2001. Construction commenced in early 2002 and was completed in 2003. After several test burns in 2003, subbituminous coal became the sole fuel source at the beginning of 2004. The commenter has no plans to switch back to bituminous coal in the future at such units. In fact, such an occurrence would be extremely unlikely, since the move was made to meet more stringent permanent NO_x requirements for these units. Using EPA's methodology, the baseline heat input for these units will be multiplied by 1.0 when computing the number of allowances to be allocated to such units either for the State trading program budget or for a Federal trading program administered by EPA. However, as these units will be combusting subbituminous coal when the Hg reduction requirements become effective, such units will be unfairly penalized, since they will not be allocated allowances based on the coal actually being burned, which will result in approximately 25 percent fewer allowances for each unit. EPA should not punish units that switched fuels to comply with earlier environmental requirements not related to the CAMR, by allocating allowances based on the fuel type burned in an arbitrary baseline year, 1999, rather than the fuel being burned at the time when the rules are actually finalized.

Moreover, there may be Utility Units that have done the opposite of this commenter (i.e., that have instead switched to a higher rank coal since 1999). If EPA were to use 1999 as the determining year for these units, their owners would receive a windfall of allowances, because the proposed methodology would base the allowance allocation on a coal type that is in fact no longer being burned.

To remedy this, this commenter suggests the following approach. EPA should use as the determinate for which coal rank multiplier to apply, the rank of coal that was combusted by such unit in the year the CAMR rule is finalized. Ideally, the goal should be to award allowances based on the rank of coal that a unit is actually burning. Alternatively, EPA should specifically

allow for units like the commenter's that switched fuels to a lower coal rank to petition EPA and, if States are actually allocating allowances to Hg budget units, the relevant State, to receive an adjustment to the coal rank factor in recognition of any situation like the one described above that would allocate Hg allowances in an inequitable manner to units that switched fuels.

Response:

EPA is using 1999 coal type as the basis for the adjustment of the baseline for establishing plant mercury allocations to be used in developing the state and tribal emission budgets for the final rulemaking. However, in the example allocation methodology for states to allocate at the unit level EPA is finalizing a different approach. EPA's example allows states to use baseline heat input for the years 2000 through 2004 and coal type for those years. Under the model trading rule, EPA notes that States and Tribes have the authority to allocate at the unit level as they choose. See Chapter 5 and final rule preamble for further discussion of emission budgets and allocation methodology.

Comment:

One commenter (OAR-2002-0056-5548) stated that EPA should adjust the Hg allowance allocations, by coal rank, to reflect the disparity of Hg removal efficiencies that NO_x and SO_2 controls have among coal ranks in any emissions trading program established under sections 111 or 112. This commenter, and others, agreed with EPA's proposal that coal rank emission control disparities justify using differing allowance allocation adjustments for each coal rank. However, the commenter argued that the allowance allocation adjustment factor for subbituminous coals should be increased from the proposaled factor of 1.25 to a higher factor of 1.5.

Response:

EPA is finalizing coal adjustment factors for the purpose of establishing state emission budgets of 1.0 for bituminous coals, 1.25 for subbituminous coals, and 3.0 for lignite coals. These adjustment factors are considered to be appropriate numbers based on the test data currently available. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Indian Country Emissions Budgets, EPA, March 2005.

Comment:

One commenter (OAR-2002-0056-5548) suggested that it should be obvious that EPA's allowance allocation approach, and the similar approaches advocated by Southern, UARG, and others, based on speciation and control issues, are fundamentally flawed. The primary question has been articulated by WEST Associates' comment that "for facilities that would have to purchase allowances, WEST Associates recommends that an additional allocation adjustment factor be applied that promotes equitable allowance distribution, particularly in Phase I of the cap" program reasoning that "it is critical that the allocations of mercury allowances reflect the

relative level of mercury control for bituminous, subbituminous and lignite coal ranks that will be achieved, within each coal rank, by the SO_2 and NO_x controls required under the CAIR by 2010." That this comment, and similar comments by Southern, UARG, and the SEC that EPA has cited in the NODA, is a misconception seems clear. There is absolutely no reason to adjust allowance allocations for purchasers of allowances based on relative levels of Hg reduction capability among coal ranks because purchasers of allowances are not reducing anything; they are simply buying allowances representing reductions made by others. That is the very point of the entire co-benefits cap-and-trade approach, where allowance purchases, and not controls, are the means to compliance for many sources. It is equally obvious that allowance purchasers do not pay different prices depending upon the rank of coal they burn. A purchaser of Hg allowances has the same equitable status regardless of the rank of coal burned. The only relevant consideration at issue is the price at which these three classes of allowance purchasers (bituminous, subbituminous, and lignite) must buy allowances. And that price is exactly the same between all of the coal ranks.

Response:

EPA is finalizing coal adjustment factors for the purpose of establishing state emission budgets of 1.0 for bituminous coals, 1.25 for subbituminous coals, and 3.0 for lignite coals. These adjustment factors are considered to be appropriate numbers based on the test data currently available. For further discussion see final rule preamble (section IV.C.4) and Technical Support Document for the Clean Air Mercury Rule Notice of Final Rulemaking, State and Indian Country Emissions Budgets, EPA, March 2005.

Comment:

One commenter (OAR-2002-0056-5332) stated that the modeling results reported in the NODA do not fill the gap. Because the modeling was done by numerous stakeholders with different objectives, crucial assumptions (e.g., demand growth; natural gas prices; availability, performance, and cost of control technologies) vary, with no attempt at systematic inquiry. Moreover, the results are not presented in uniform metrics and, therefore, in many cases are not comparable. The commenter urged the Agency to undertake a systematic, transparent modeling effort, along the lines that the Clean Energy Group and other stakeholders have recommended.

Response:

EPA is finalizing a cap-and-trade approach under section 111. Analyses in support of the process will be presented in the final CAMR Regulatory Impact Analysis document.

1. EPA received numerous comments on subcategorization by coal type and the speciation profiles resulting from the combustion of various types of coal. EPA sought additional specific data and information on the speciation profiles of various types and blends of coal.

Comment:

One commenter (OAR-2002-0056-5484) provided detailed information and a technical report with its comments (OAR-2002-0056-2948) of June 29,2004, on the speciation of Hg in coal-fired power plant plumes. In the NODA, EPA has asked for more information on Hg speciation and has also indicated that it is performing a benefits analysis that attempts to estimate the reduction in adverse human health effects that will occur as a result of reducing Hg emissions from coal-fired power plants. To this end, this commenter wishes to provide more information to supplement the information provided in June and to re-state the implications of this information. OAR-2002-0056-5484 is the latest summary of the research which has shown that the fraction of Hg emitted as oxidized Hg from coal-fired power plants is rapidly converted to elemental Hg. Current models do not account for this conversion. Research is underway by EPRI and others to better understand the chemical mechanisms that explain this observation and to incorporate the mechanisms into air quality models. The most important implication of this research finding is that, because the observed transformations are not taken into account in current assessments, current estimates of the benefits from reducing power plant Hg are overestimated. This overstatement applies to the results of the most comprehensive assessment conducted to date – that conducted by EPRI – which already shows that very small Hg deposition and exposure reductions will result from either the cap-and-trade or MACT approaches. EPA should include these transformations in whatever benefits estimation it conducts.

Comment:

One commenter (OAR-2002-0056-5556) referred to the speciation of Hg and noted that new information challenged the estimated lifetime of elemental Hg before it is deposited. Also, new data are demonstrating the oxidation of elemental Hg to reactive gaseous Hg during periods of enhanced photochemical activity with high ozone and warm temperatures (OAR-2002-0056-5557).

Response:

EPA has addressed the commenter's issue through the application of the Community Multiscale Air Quality (CMAQ) modeling system in estimating current and future levels of total mercury deposition for the purposes of this rule. This sophisticated photochemical air quality model is able to differentiate across Hg emissions species and account for the complex atmospheric reactions as referenced by this commenter. The model and these specific reactions are detailed in the Air Quality Modeling TSD (docket #OAR-2002-0056-6130).

Comment:

One commenter (OAR-2002-0056-5564) noted that the principal business of San Miguel Electric Cooperative, Inc., is the production of electric energy in South Central Texas. Production includes one coal-fired power plant and one lignite mine. The lignite mine supplies

fuel only for the San Miguel Generating Station and produces, on average, 3.3 million tons of lignite/year. The one generating unit fires only lignite provided by this mine and comprises 100 percent of San Miguel's generating capacity; average yearly output is 3.2 million MWh.

The commenter provided comments on the issues of Hg speciation. The commenter's unit has an ESP and a wet FGD system for controlling PM and SO_2 and has performed two stack tests for Hg. These tests were conducted in 2002 and 2004 using appropriate methods and the test results were provided in the comments.

Response:

EPA appreciates the submission of the data.

Comment:

The commenter (OAR-2002-0056-5490) stated that their comments are all related to the second section, "Electric Utility Sector Modeling and Hg Speciation," especially as it relates to Gulf Coast lignite. The commenter continued its research into the Hg content of the coals it combusts, the speciation of the Hg in the flue gases prior to existing control devices, the removal efficiencies of the existing control devices and the Hg emissions (and speciation) from its stacks. Unfortunately, the reports for the testing had not been finalized at this time. The commenter also participated in four DOE Hg control technology projects. The results of Hg analysis on samples of coal taken through October 31, 2004, from pulverizer feeders at the commenter's nine coal-fired units were provided in the comments. All of these units, except Sandow Unit 4, burned blends of Gulf Coast lignite and western subbituminous coal. The minimum Hg-in-coal values are from high percentage subbituminous samples and the maximum values are from high percentage lignite samples. Sandow Unit 4 burned Gulf Coast lignite only.

The Cl in the Gulf Coast lignite ranged from less than 1 part per million (ppm) to 170 ppm, which is less than the 1999 ICR Part II analysis indicated. Chlorine content affected the speciation of Hg generated from firing coal.

Response:

EPA appreciates the submission of the data.

Comment:

Two commenters (OAR-2002-0056-5456, -5505) mentioned that EPA is seeking input on issues of Hg speciation. The NODA states, "During this data collection effort, incoming coal shipments for all coal-fired power plants in the U.S. were tested for Hg content (for calendar year 1999)." Perhaps the more fundamental issue than the speciation of the Hg is one of if the Hg content of the coal is accurate in the EPA ICR database. There has been much controversy expressed that the proposed MACT Hg emission standards for subbituminous coal are too high creating a "compliance coal" for Hg, particularly for PRB coal. This conclusion was based upon

an analysis of the EPA coal Hg content database.

Since that time, there has been some testing of advanced Hg control technologies with various types of coals and control configurations. Also included in these analyses were a quantification of the coal Hg content, and inlet total vapor (Hg).

The commenter was a participant in the testing done at Sunflower Electric's Holcomb Station, located near Garden City, Kansas. The plant burns Wyoming PRB coal, and has a SDA/FF control configuration, which is widely considered to be a "typical" configuration for future coal-fired plants; particularly those that consume PRB coal. Mercury reduction testing took place at this plant, funded by the DOE and others. The results of the test are presented figures 1 and 2 of OAR-2002-0056-5456 , and show that in this test PRB coal significantly exceeds EPA's proposed MACT Hg emission limit of 5.8 lb Hg/TBtu for subbituminous coal.

Comment:

Commenter OAR-2002-0056-5505 provided information from Arapahoe Unit 3, a 44 MWe PRB coal-fired unit in the Denver metro area. The unit is equipped with a reverse air fabric filter and a dry sodium injection system for SO_2 removal. Testing at this plant occurred over a two-week period in May 2004 to evaluate the use of Amended Silicates for Hg removal. The interesting part of the work from the perspective of the commenter is that it included two separate PRB coals. These coals were burned separately, and were not mixed during the test. One of the coals had significantly higher Hg content that the other coal.

The commenter provided results for the higher Hg-content coal tests. In both tests, PRB Coal A yielded significantly higher results than EPA's proposed MACT emission limit of 5.8 lb Hg/TBtu. From the final report, PRB Coal A "had nearly twice the Hg of [PRB Coal B] with a Hg content of 0.071 ppm (as-received basis). [PRB Coal A] yielded flue gas vapor-phase Hg concentrations in the range of 12 to 16 $\mu g/Nm^3$. For Xcel's samples from [PRB Coal A] shipments to Arapahoe, their average Hg content has been measured as 0.06 ppm, somewhat lower than the value for the [PRB Coal A] sample obtained during the May trial."

Response:

EPA appreciates the commenter's input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5502) referenced Hg speciation. Test results obtained by the commenter in the last year have not markedly changed the speciation correlations developed from the ICR. While coal Cl content appears to drive the degree of flue gas Hg oxidation, other factors may also have a noticeable effect on this process; tests and chemical

modeling studies are seeking to quantify the role and significance of these other factors. Speciation continues to be viewed as important for determining the most applicable and cost-effective controls, the achievable emission levels, and, to a certain extent, the potential impact of emissions from a given plant on Hg deposition onto downwind water bodies.

Response:

EPA appreciates the commenter's input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5497) stated that subsequent to the ICR stack sampling in 1999, Hg speciation measurements have been taken as part of research studies sponsored by DOE, EPRI and others. These studies have explored, among other things, the effect of SCR on Hg oxidation and Hg removal using ACI. In addition, a number of coal-fired power plants have conducted their own sampling of Hg emissions to determine the levels and species of Hg that are emitted.

In general, this additional testing has produced results that continue to show Hg emission variability like that seen during the ICR stack testing. As EPRI's NODA comments indicate (see OAR-2002-0056-5469), these recent Hg results do not substantially change the Hg speciation correlations that EPRI produced using the ICR data.

Response:

EPA appreciates the commenter's input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5494) noted that the NODA solicits input on, among other matters, issues related to "Hg speciation" and the results of four approaches of modeling Hg emissions under various emission control equipment deployment scenarios. All those model calculations start with certain assumptions about the relative proportions of the chemical composition of Hg emissions exiting the stacks (three species – elemental, ionized, and particle-bound) from coals classified as bituminous, subbituminous, and lignite.

This commenter addresses two issues relating to coal ranks/Hg speciation: (1) uncertainty associated with compliance with the proposed regulations for coal used at several Southwestern power plants, and (2) questions associated with the appropriateness of developing

the proposed Hg rule utilizing the ICR III database's Hg emissions data segregated under the three coal rank classifications. Specifically, these comments address unique problems in applying the ASTM methodology referenced in the proposed rule to determine coal ranks and compliance obligations.

EPA's proposed rule refers to the ASTM coal ranking methodology and sets different Hg emission limitations for different coal ranks. However, the ASTM coal ranking methodology may not be appropriate for regulating Hg emissions from certain coal-fired power plants. The ASTM methodology is based on analyses on a "moist" basis, or the moisture content of the coal in the mine. ASTM D388-99 clearly requires that coal rank should be determined while the coal is in the mine. Coal ranking classification made any other way, such as under "as received" is designated by ASTM D388-99 as "apparent rank."

The EPA's ICR data collection efforts discuss reporting coal properties on an "as received" basis at each respective coal fired power plant. In some cases, as discussed below, coal determined to be subbituminous in the mine according to the ASTM methodology could very well transform to bituminous when it is "received" at the plants, stored on site, or while combusted in a boiler, because its "inherent moisture" value could change.

Moreover, in the case of coals whose heating value falls in the overlapping region between 10,500 to 11,500 Btu/lb, only an agglomeration test can definitively determine its actual coal rank (D388-99). The proposed rule does not contemplate situations like those identified here and raises considerable ambiguity as to the applicable regulatory requirements. This situation is very different from the "coal blending" scenario addressed in the proposed rule to establish the appropriate emission limit. This commenter believes that the rule should be made very clear as to what the operator's regulatory obligations are. Specifically, the commenter requests that EPA expressly state in the rule where the coal rank should be determined: at the mine, "as received" at the plant, or when the coal is combusted in the boiler.

EPA developed the rule, as noted above, by segregating Hg emissions test data (ICR III) from 81 units by the rank of the coal used during the emission tests. In this process, coal data were taken from the ICR III test reports, and constituted coal characteristics on an "as received" basis. Data for one of the four units used in calculating the MACT level for subbituminous coal came from the commenter's Cholla Power Plant (Cholla Unit 3), and in 1999 Cholla reported the coal used during the ICR III tests to be "Bituminous/Subbituminous." Recently, Cholla has reviewed coal data submitted to the EPA under ICR III and ICR II throughout 1999, and concluded that Cholla burned bituminous coal most of the time. In fact, that review has also concluded that Cholla Unit 3 burned bibuminous coal during the ICR III testing. Based on these conclusions, the commenter believes that EPA segregated ICR III data from Cholla Unit 3 in the incorrect subbituminous category.

The commenter's review of the ICR III data for the other three top performing units (used to calculate the subbituminous MACT level) suggests that at least two of those units' coal ranks may have been incorrectly classified . Thus, if the coal ranks have indeed been misclassified before calculating the MACT levels for the subbituminous coal category, the coal rank-based

determination of Hg emission limitations may be in error.

The commenter understands that similar concerns were included in the comments submitted to the EPA in the proposed rulemaking by the Subbituminous Energy Coalition (SEC). Therefore, the commenter respectfully requests that EPA reassess the classification of ICR III Hg emissions test data by coal rank and the subsequent statistical analyses done in developing the proposed MACT levels/national Hg emissions cap and trade program (and its allowance allocations).

Commenter OAR-2002-0056-5494 agreed that EPA has found that the Cl content of coal determines the relative proportions of various chemical species of Hg emitted. For example, combusting Eastern bituminous coal (with its high Cl content) creates higher proportions of ionized and particle-bound Hg, while Western subbituminous, Western bituminous, and lignite coals (all with much lower Cl content) create a higher proportion of elemental Hg. EPA has also found that ionized and particle-bound Hg emissions are more efficiently controlled in existing pollution control devices (such as SO_2 scrubbers and PM control devices). Therefore, modeling results of Hg emissions from stacks depend on the assumed relative proportions of the three Hg species.

The commenter believed that regulating Hg emissions on the ASTM methodology of coal ranking (based primarily on heating value) may not be appropriate, at least where the Btu value for bituminous and subbituminous coal overlaps (as noted by ASTM D388-99). EPA's proposed rule sets MACT levels based on coal ranks: for example, the proposed emissions limits are 2.0 lb/TBtu for bituminous and 5.81 lb/Btu for subbituminous coals. There are several plants in the Western and Southwestern U.S. that utilize coal whose rank can vary between bituminous and subbituminous from time to time, even for coal coming from the same seam. Given below are two different types of examples where the commenter believes such changes can occur.

First, the commenter considered the case of coal whose heating value falls in the "overlapping region" between bituminous and subbituminous coals. Several Western power plants are "mine-mouth" plants, and hence, restricted to utilize coal burned in the adjacent mine. One such plant, the commenter's Four Corners Power Plant, uses coal from the Navajo Mine on the Navajo Reservation in Northwestern New Mexico. Navajo Mine's coal has fairly low heating value (typically under 9,000 Btu, on an "as received basis") and very high ash content (typically 20-25 percent). Over the past decades, the mine operator assured the commenter that its coal was subbituminous coal.

If the ASTM methodology is utilized, the Navajo Mine's coal's "mineral-free" heating value often falls in the 10,500 to 11,500 Btu range, the overlap region between bituminous and subbituminous coal classification. Under such conditions, ASTM methodology requires an "agglomeration test" to determine the coal rank. Very limited agglomeration tests conducted by the commenter indicate that the Navajo Mine's coal could be bituminous, contrary to long-held belief and assurances from the coal supplier. EPA's proposed rule (69 FR 4665) emphasizes the significance of coal rank in the engineering design of power plants and their operation. Therefore, Four Corners, and several other plants in the Southwest designed to burn

subbituminous coal, may be forced to comply with the Hg emission limitation applicable to bituminous coal.

The commenter reported that its experience with coal from the McKinley Mine in New Mexico used at the Cholla Plant provides a situation completely different from the above example. There, the "apparent rank" on occasion falls in the range of 11,300 to 11,800 Btu/lb range. If the "Free Swelling Index" is applied to that coal, that coal is non-agglomerating, and thus, will be classified as subbituminous. Under those circumstances, coal from the McKinley Mine could vary from bituminous to subbituminous on a daily basis.

The commenter reported that EPA staff said that they never envisioned that plants would undertake "agglomeration tests" on a routine basis, as it is time-consuming and expensive. This situation leads to two potential problems. First, the commenter notes that there is considerable uncertainty concerning the plant's compliance obligations under both MACT and cap-and-trade regulatory approaches (i.e., via calculation of the national cap as well as the Hg allowance allocations). Second, the commenter notes that in situations like the one described above, it may be possible to "blend coals" in such way to bring its heating value to just below the threshold level to classify it as subbituminous. Such a situation can create opportunities for "gaming" the regulatory system. These potential scenarios are untenable and should be clearly addressed in the final rule.

The commenter related the second issue to variability in moisture content, which can change during the mining process, transportation to the power plant, and combustion in a boiler. For example, the Cholla Power Plant (as well as certain other power plants in the Southwest) utilizes coal from several mines, including the McKinley Mine in New Mexico. Typically, McKinley Mine adds about 3 to 4 percent moisture in dust suppression activities. Adding moisture reduces its heating value, and according to the ASTM methodology coal rank is determined on a moist, mineral free basis for subbituminous coals. At the plant, storage of coal in the open (prior to combustion) and pulverization can result in loss of some moisture.

The commenter reported that when EPA assembled the ICR II and III database, no guidance was given to plant operators about any adherence to ASTM methodology in developing the data and reporting it to EPA. Accordingly, plant operators relied on the information on coal ranks provided by the coal suppliers, and reported the same data to the ICR database. It appears that EPA developed the coal rank-based Hg rule, and the ASTM methodology was brought in later as an afterthought. Upon careful review of the ASTM methodology, the commenter believes that potential problems like the ones discussed above exist. If EPA retains the coal rank-based Hg regulatory scheme, then the commenter recommends that the rule should clarify that the coal rank reported by the coal supplier (mine) will be the basis of determining the appropriate Hg emission limitation. This commenter believes that forcing the plants to conduct agglomeration tests on a routine basis is unreasonable and will create uncertainty in plants' compliance obligations.

Because Cholla Unit 3 was one the four "top performing" units used to calculate the MACT level for the subbituminous coal category, the commenter recently reviewed the coal data

reported in 1999. The commenter found that the coal rank data was reported as "Bituminous/Subbituminous" during the ICR III tests. After the proposed rule was published with its reference to ASTM methodology, the commenter recently calculated the Btu value of the coal on a moist, mineral-free basis, utilizing the coal analysis data reported in Cholla's ICR III test report. These calculations, as per ASTM methodology, lead us to conclude that Cholla Unit 3 indeed burned bituminous coal during the ICR III testing. Accordingly, the commenter believed that ICR III test data from Cholla Unit 3 were inappropriately classified under the subbituminous coal category, and consequently, use of data from that unit to calculate the subbituminous MACT level may be in error.

The commenter had also evaluated the coal ranks reported for some of the units that were tested under ICR III, and the commenter believed that EPA's grouping of units under bituminous/subbituminous categories may be erroneous in certain cases. The commenter provided a table of the coal Btu values from the ICR III test reports for the four units used in setting the MACT level for subbituminous coal. If the ASTM guidelines on Btu content were to be used, three of those four (i.e., AES Hawaii, Clay Boswell Unit 2, Cholla Unit 3) units clearly fall under the bituminous category, rather than subbituminous category. This raises questions about the validity of the proposed MACT levels for subbituminous coal, and raises a similar problem for the cap-and-trade proposal.

The commenter is aware of the uncertainty with the type of coal used (and associated potential misclassification) during the ICR III tests at the Valmont Plant in Colorado reported by Xcel Energy. Data from that plant was used to calculate the MACT level for the bituminous coal category. However, had the coal indeed been subbituminous (rather than the assumed bituminous), the proposed MACT levels for both bituminous and subbituminous would be significantly different.

The commenter stated that, based on the new information on the possible misclassification of coal ranks in the ICR III Database presented here, they believed that EPA should reassess the MACT levels and cap-and-trade allowance allocations included in the proposed Hg rulemaking. This commenter believed that EPA should address the unique compliance uncertainty created for several Western/Southwestern plants using certain coals whose heating value (Btu) falls in the overlap area for bituminous and subbituminous coal ranks. Therefore, should EPA retain the coal rank-based approach to regulate Hg emissions, the commenter recommends that EPA use the same Hg emissions limitation for low Cl content Western bituminous coal and subbituminous coal.

The commenter also believed that the Cl content of the coal is a better basis for regulating Hg emissions than the proposed coal rank-based approach, which relies on the ASTM methodology that was never intended and is not appropriate for characterizing Hg emissions. Finally, in the event that EPA retains the coal rank-based approach of regulating Hg emissions, this commenter recommends that plants using Western bituminous coal be subjected to MACT levels and allowance allocations identical to those plants using subbituminous coals.

Response:

EPA appreciates the commenter's input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

Commenter OAR-2002-0056-5548 noted that commenter OAR-2002-0056-2535/5505 had urged EPA to reevaluate the MACT determination for Wyoming subbituminous coals to account for large differences in Wyoming PRB and other western subbituminous coals. Commenter OAR-2002-0056-2535/5505 is, in effect, asking EPA to further subcategorize subbituminous coals based on differences, such as a distinction between ASTM sub-classifications within the subbituminous rank, as they discuss in their comments. Commenter OAR-2002-0056-5548 believed that the commenter OAR-2002-0056-2535/5505's argument points out one of the fundamental flaws with the attempt to subcategorize by coal rank, because rank is not predicative of coal properties of relevance to Hg emissions and control. Furthermore, if EPA were to do so for subbituminous coal, it also must further subcategorize bituminous coals based on the even greater differences in bituminous coals from different regions of the country. Commenter OAR-2002-0056-5548 believes that, at a minimum, EPA should subcategorize bituminous coals by rank (High volatile A, B, and C, medium volatile, and low volatile), and further by geographic region (western, mid-continent, northern, central, and southern Appalachia). Within these regions, bituminous coals are produced from individual seams which themselves exhibit large differences in coal properties. A decision by EPA to further subcategorize one rank coal without doing so for all ranks of coal would clearly be arbitrary and would fail to ensure an equitable treatment for coals of all ranks, which EPA states as one of its objectives.

In its original comments on the rule and in these NODA comments, commenter OAR-2002-0056-5548 demonstrated, using the IRC Part II coal analysis data, that 62 percent of all subbituminous coals sampled would meet the proposed 5.8 lb/TBtu MACT limit with no Hg reduction, largely eliminating the speciation or any other control issue. The average subbituminous coal has a Hg content of 5.7 lb/TBtu, thus making subbituminous coal, in aggregate, a compliance coal, given the proposed 12-month averaging period of the rule.

In its comments, commenter OAR-2002-0056-2535/5505 attempts to refute this compliance coal demonstration by presenting ICR Part III emissions data from 10 plants burning Wyoming PRB coal, purporting to show that Hg emissions from the majority of these plants are in excess of the 5.8 lb/TBtu limit. EPA should discount this for two reasons. First, commenter OAR-2002-0056-2535/5505 acknowledges in its comments that the ICR Part III data, which consists of only short-term sampling at 80 power plants, is highly suspect. Commenter OAR-2002-0056-5548 strongly concurred with that observation and point out that none of the units that meet the data quality criteria burns a Wyoming PRB coal. Therefore, the attempts of commenter OAR-2002-0056-2535/5505 to use the ICR Part III data to support a conclusion concerning plant emissions contradicts their clear understanding of the limitations of the ICR Part III data.

Second, the IRC Part II data set, on which commenter OAR-2002-0056-2535/5505 relied, is much more substantial and robust, because it contains the Hg contents of thousands of coal samples from most mines, sampled as delivered to most power plants in the country for a full year. Commenter OAR-2002-0056-5548 provided a table reporting the mean and median Hg contents from the ICR Part II data base for the 509 coal shipments sampled as delivered to the nine plants for which commenter OAR-2002-0056-2535/5505 presented emissions data. Contrary to the SEC's assertion, six of the nine plants (67 percent) received coals in compliance with the proposed 5.8 lb/TBtu limit in 1999, and the three that did not would require an average reduction of only 10 percent to come into compliance. That reduction is well within the range of EEI/CRA's subbituminous EMF for a CS-ESP. Thus, assuming only a modest reduction across existing emission control equipment, these plants would require no further reduction to come into compliance. The average Hg content of coals delivered to the same nine plants in commenter OAR-2002-0056-2535/5505's comments was 5.2 lb/TBtu, further supporting the commenter OAR-2002-0056-5548's conclusion that the 5.8 lb/TBtu MACT limit effectively would denominate subbituminous coals as compliance coals.

Commenter OAR-2002-0056-2535/5505 stated that "elemental mercury comprises 70-80 percent for the total mercury emitted from the furnace" for subbituminous coal-fire units. They do not provide a source for this statement, but it appears to overstate the percentage of elemental Hg in the flue gas of such units. An analysis of the ICR Part III data for Hg speciation at the inlet to the last control device at each subbituminous-coal-fired station reveals an average elemental Hg concentration of 59 ± 23 percent. Some particulate or oxidized Hg may have been removed ahead of the flue gas measurement point, so this should be considered an upper bound on the average percentage of elemental Hg in the flue gas for subbituminous coal-fired units. Note that this average excludes those plants identified by commenter OAR-2002-0056-2535/5505 as misidentified by the EPA as burning only subbituminous coal.

Commenter OAR-2002-0056-2535/5505 contended that the imputed emission factors calculated from EPA's proposed allowance adjustment factors under section 111 results in "relatively little" subcategorization. Commenter OAR-2002-0056-5548 opposes the imposition of any allowance adjustment factors. The commenter believed that too little is known at present about Hg emissions and control technology to ensure that they are equitable and result in achievable emission limits (a position with which commenter OAR-2002-0056-2535/5505 concurs). The commenter also contended the development of Hg-specific control technology will obviate the rationale for allowance adjustments in the future. Nevertheless, commenter OAR-2002-0056-2535/5505 would support the use of EPA's section 112 MACT limits as the basis for allowance adjustment factors. This would simply create under the guise of a cap-and-trade program the same inequity as in the MACT proposal, under which subbituminous coal fired units would receive sufficient allowances as to require no Hg reductions, and most likely receive excess allowances from which they would profit by selling them to bituminous coal-fired units which face a stringent, and in some cases unachievable, compliance burden.

Response:

EPA believes that the comments provided by commenters OAR-2002-0056-5494 and -

5548 relate, variously, to the issues of subcategorization (either more or fewer subcategories) and the use of the ASTM ranking scheme to delineate the subcategories, rather to the issue of Hg speciation. EPA has addressed, earlier in this document, other comments related to the issue of subcategorization and has presented its rationale for the use of subcategories.

We are, however, somewhat perplexed regarding the comments related to a utility "not knowing" the rank of coal being fired and on the use of the ASTM classification methodology as the basis for determining the rank of coal burned, and, thus, "membership" in the appropriate subcategory. EPA based its subcategorization on the coal rank information provided by the utility, not on the coal analysis data provided by the utility. That is, if a utility reported that their coal was (e.g.) "subbituminous," EPA did not question the statement. During the period of the ICR, EPA requested that the responding utilities provide to EPA only the Hg- and Cl-contents of their coals as new information. The remaining coal information requested (e.g., coal rank; heating value; moisture, ash, and sulfur content) was that information already being provided to the DOE. Each U.S. utility company (including combined heat and power companies) is required by law to submit to the DOE/EIA for each Utility Unit the rank of coal burned, on a monthly or annual basis, on at least one of the following forms:

EIA Form-423: Monthly Cost and Quality of Fuels for Electric Plants Report ("Column 'c'Fuel)
EIA Form-767: Steam-Electric Plant Operation and Design Report ("Fuel Code")
EIA Form-860: Annual Electric Generator Report ("Energy Source Code")
EIA Form-860m: Monthly Update to the Annual Electric Generator Report ("Energy Source Code")
EIA Form-906: Power Plant Report ("Energy Source")
EIA Form-920: Combined Heat and Power Plant Report ("Energy Source")

Thus, utility companies are currently obtaining the coal rank information being reported to DOE from someone, somehow to comply with this legal requirement. EPA is not asking for any additional information or analyses upon which to establish a given Utility Unit in a subcategory for purposes of either the final NSPS or cap-and-trade provisions. Rather than being able to "game" the system, units that blend two or more ranks of coal are required to use specified procedures for determining their applicable NSPS emission limit.

EPA continues to believe that the ASTM ranking methodology is the one most widely recognized within the industry and, therefore, is appropriate for this rulemaking. Given the existing legal requirement to provide DOE with the coal rank being utilized, EPA believes that the industry knows what coal rank it is consuming in its units.

2. EPA sought comment on if/when a standard (or average) speciation profile should be used for either the CAA section 111 or CAA section 112 regulatory approach.

Comment:

One commenter (OAR-2002-0056-5475) stated that under Part II, Sub-Part C of the NODA, EPA indicates that it received comments related to the speciation of Hg. The commenter stated that speciation is fundamentally important since the ability of control devices to remove Hg is directly related to the form of Hg in the flue gas. The three species of Hg that exist in plant emissions are elemental, ionic/oxidized, and particulate. Oxidized and particulate are known to be the more easily captured forms of Hg. Average Hg speciation data from the 81 power plants that were the basis of the MACT floor calculations, is set forth in the NODA (69 FR 69871). The calculated averages of the speciated Hg forms across all coal types were: 54 percent elemental, 43 percent oxidized, and 3 percent particulate.

Response:

EPA appreciates the commenter's input to the record on the status of control technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5475) objected to the notion of using an average speciation profile to predict the characteristics of Hg emissions from coal fired utilities. The percentages of the three forms of Hg emissions can vary widely from facility to facility, even in the same coal category. For example, it has been determined that within a given coal category the proportion of oxidized Hg emitted is proportional to the Cl content of the coal. Commenter OAR-2002-0056-2038 noted that average speciation for electric utilities range between 10 percent and 90 percent for the oxidized form. The Brookhaven National Laboratory's May 2003 study utilized data from the Bruce Mansfield Plant in Shippingport, PA, and the Monticello Power Plant in Monticello, TX. The fraction of the oxidized form of Hg between these two plants varied between 19.7 percent and 60.4 percent, respectively. Given the disparate speciation data that exists for Hg emissions, this commenter recommends that a sensitivity analysis be performed to evaluate the effect that the range of values for the oxidized form of Hg has on the proposed rule.

Response:

EPA appreciates the commenters concerns. Please see EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005) for a discussion of the importance of speciation for mercury capture. Also, please see Chapter 7 of the Regulatory Impact Analysis for a discussion of how we took speciation into account in our power sector modeling and see Chapter 8 for a discussion of how we took speciation into account in our air quality and deposition modeling.

Comment:

Two commenters (OAR-2002-0056-5510, -5548) said that an average speciation profile cannot capture the large degree of variability and uncertainty associated emissions from different coal types, and should not be used for either section 111 or 112 regulation.

In the case of MACT regulation, if the standard is set based upon an average speciation profile, coals with greater Hg concentrations will not be able to comply–even if the unit is meeting a targeted percentage reduction. For example, the average Hg content of bituminous coal reported in the ICR Part II data is 8.4 lb/TBtu. Assuming the availability of a Hg control technology able to achieve 50 to 70 percent reduction (DOE's goal for 2010), the "average" bituminous coal could achieve an emission rate of 2.5 to 4.2 lb/TBtu. However, coals from the State of Ohio, which have an average Hg concentration of 15.7 lb/TBtu, would need to achieve 75 to 85 percent removal to meet a standard in this range, beyond the range of the hypothetical then-available technology. As a result, these coals could not be used in compliance with the MACT.

Although this risk may be somewhat lessened under a cap-and-trade rule, because operators have the potential ability to purchase allowances, there is no assurance that allowances will be available in sufficient quantity to meet compliance needs. To the degree that allowances are not available, the explicit compliance problem under the MACT described above becomes effectively the same liability under the cap-and-trade program.

Response:

EPA is finalizing a cap and trade rule. Please see the CAMR preamble for a complete discussion. EPA appreciates the commenters concerns. Please see EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005) for a discussion of the importance of speciation for mercury capture. Also, please see Chapter 7 of the Regulatory Impact Analysis for a discussion of how we took speciation into account in our power sector modeling and see Chapter 8 for a discussion of how we took speciation into account in our air quality and deposition modeling.

Comment:

One commenter (OAR-2002-0056-5502) referenced using average vs. individual power plant speciation in modeling and used individual speciation in the model runs conducted for it to gain insights into the potential changes in deposition patterns as a result of different Hg emission reduction scenarios. The commenter recommends that EPA do the same to develop similar insights, as these are important to inform decisions on cap-and-trade vs. MACT.

Response:

EPA is finalizing a cap and trade rule. Please see the CAMR preamble for a complete discussion. EPA appreciates the commenters concerns. Please see EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An

Update, EPA/Office of Research and Development, March 2005) for a discussion of the importance of speciation for mercury capture. Also, please see Chapter 7 of the Regulatory Impact Analysis for a discussion of how we took speciation into account in our power sector modeling and see Chapter 8 for a discussion of how we took speciation into account in our air quality and deposition modeling.

Comment:

One commenter (OAR-2002-0056-5497) stated that given the repeated concerns voiced about Hg "hot spots," it makes sense to use the best estimates of Hg speciation in any dispersion modeling. EPA's 1999 ICR request produced a year of detailed coal data for all coal-fired power plants in the U.S. These coal data can be used along with Hg speciation correlations that EPRI developed from the 1999 ICR Hg stack sampling to produce Hg speciation estimates for every coal-fired unit in the country. This is exactly how EPRI modeled Hg deposition in the U.S. EPRI's modeling results were provided in EPRI CAMR comments dated June 16, 2004 and in the comments EPRI is submitting in response to this NODA. The commenter believes that EPA should follow a similar approach in any Hg deposition modeling it may perform. EPA should not use an average speciation value for each coal rank.

Response:

EPA appreciates the commenters concerns. Please see EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005) for a discussion of the importance of speciation for mercury capture. Also, please see Chapter 7 of the Regulatory Impact Analysis for a discussion of how we took speciation into account in our power sector modeling and see Chapter 8 for a discussion of how we took speciation into account in our air quality and deposition modeling. EPA has addressed the hot spots issue in the revision Federal Register notice and in the Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls in the docket.

3. Is it currently feasible, or will it be feasible within the compliance timeframes of the proposed rule, to accurate monitor a source's Hg emissions by species?

Comment:

As part of the commenter's (OAR-2002-0056-5490) Mercury Research Program, they had purchased two Hg CEMS. The analyzers, manufactured by Nippon, are "dry" monitors and appeared to be fairly reliable. Most of the problems that the commenter saw had been in the sample conditioning system. A great deal of effort had gone into increasing the reliability of the sample conditioning system. High temperatures had to be maintained throughout or fouling of the glassware would occur. The commenter has installed a completely glass-lined probe to help maintain closer tolerances with sampling temperatures. Even with all the effort put into making the system run reliably, they are only getting about 5 days of continuous operation without

significant maintenance. Until these problems are resolved, it will not matter if the monitor can measure speciated Hg. The commenter's Hg CEMS are capable of measuring speciated (elemental and oxidized) Hg.

Response:

EPA believes that field tests have demonstrated Hg CEMS to be accurate and reliable. The Hg CEMS have performed adequately for several months and meet the Ontario-Hydro Reference Method specifications. Furthermore, several dry chemistry Hg CEMS are currently being tested at sites that represent the most challenging conditions and the Agency plans to share with industry the results of such experiences to facilitate the selection of appropriate monitoring methodology. EPA also agrees with the commenter that the sample conditioning system provides one of the most challenging aspects of operating a successful Hg CEMS, but feels confident that substantial advancement of the sample conditioning system will occur before the implementation of the rule and as other monitoring techniques may become available, is allowing the use of systems that can meet performance-based specifications.

The final rule requires the measurement of total vapor phase Hg, but does not require separate monitoring of speciated Hg emissions (i.e., elemental and ionized Hg). Because of the potential impact of Hg speciation on local versus broader geographical deposition, the Agency considers separate monitoring of these emissions as a need to be addressed. However, at least two current monitoring technologies can accurately monitor speciated Hg emissions. The Agency will continue to test speciated Hg monitoring technologies. If these technologies are adequately demonstrated, the Agency may consider a proposed rulemaking within four to five years after program implementation, which should provide enough lead time for development and installation of these monitoring systems.

Comment:

One commenter (OAR-2002-0056-5510) noted that speciated Hg emissions can currently be measured via the Ontario Hydro Method. However, when the tests are being conducted specific attention must be provided to the experimental method to ensure data reliability. As pointed out in the commenter's May 14, 2004, comments, EPA's IGR Part III data contain many instances of incomplete or invalid testing.

CEMS, or semi-continuous methods like proposed EPA Method 324, for the measurement of total Hg emissions are projected to be available in the 2008 time frame and would be sufficient to demonstrate compliance with the proposed standards. The commenter believed adequate information can be gathered using CEMS or semi-continuous methods for total Hg emissions, combined with periodic Ontario Hydro sampling for speciated emissions profiles, if adequate methods for monitoring speciated Hg are not developed by that time.

As noted in the commenter's May 14, 2004, comments, adequate technical data do not exist at this time to provide a reasoned basis for the allocation of allowances among coal types for purposes of an initial reduction in 2010. For this reason, the commenter recommended that

Hg monitoring begin on affected units in the 2008 time frame in order to determine prospective emissions allocations by coal type for an interim 2015 emissions cap. The analysis required for setting appropriate allocations will necessarily require speciated emissions information over the full range of operational conditions including emissions during partial load, transient operations and during maintenance events.

Response:

The final rule requires the measurement of total vapor phase Hg, but does not require separate monitoring of speciated Hg emissions (i.e., elemental and ionized Hg). Because of the potential impact of Hg speciation on local versus broader geographical deposition, the Agency considers separate monitoring of these emissions as a need to be addressed. However, at least two current monitoring technologies can accurately monitor speciated Hg emissions. The Agency will continue to test speciated Hg monitoring technologies. If these technologies are adequately demonstrated, the Agency may consider a proposed rulemaking within four to five years after program implementation, which should provide enough lead time for development and installation of these monitoring systems.

Comment:

One commenter (OAR-2002-0056-5502) referenced future availability of speciating continuous Hg monitors. Assuming the developers (and future suppliers) of continuous Hg monitors are successful in developing accurate, reliable and robust instruments for near-continuous measurements of total Hg, they should be able to enhance these to also provide near-continuous speciated measurements with 1 to 2 years after commercialization of the total Hg monitors.

Response:

At least two current monitoring technologies can accurately monitor speciated Hg emissions. EPA agrees with the commenter and the Agency will continue to test speciated Hg monitoring technologies. If these technologies are adequately demonstrated, the Agency may consider a proposed rulemaking within four to five years after program implementation, which should provide enough lead time for development and installation of these monitoring systems.

Comment:

One commenter (OAR-2002-0056-5535) stated that EPA's specific question about whether it is currently feasible, or will be feasible within the compliance time frames of the proposed rule, to accurately monitor a source's Hg emissions by species is irrelevant. EPA has already stated that continuous Hg monitors that measure total Hg have been validated and will be required for compliance with the final rule. Total Hg emissions must be reduced from these sources.

Response:

The final rule requires the measurement of total vapor phase Hg, but does not require separate monitoring of speciated Hg emissions (i.e., elemental and ionized Hg). Because of the potential impact of Hg speciation on local versus broader geographical deposition, the Agency considers separate monitoring of these emissions as a need to be addressed. However, at least two current monitoring technologies can accurately monitor speciated Hg emissions. The Agency will continue to test speciated Hg monitoring technologies. If these technologies are adequately demonstrated, the Agency may consider a proposed rulemaking within four to five years after program implementation, which should provide enough lead time for development and installation of these monitoring systems.

Comment:

One commenter (OAR-2002-0056-5497) stated that although the Ontario-Hydro Method (ASTM Method D6784-02) provides only short-term emissions data, it is currently capable of providing accurate and repeatable data on Hg emissions at the stack by species. The commenter believed that speciated data collected by EPA pursuant to its Hg ICR using the Ontario-Hydro Method clearly documents the need for subcategorization of the utility industry based on coal type in any final MACT rule.

As for continuous monitoring of Hg emissions by species, there is no commercially available monitor capable of providing Hg emissions data by species, and there is almost no possibility that a such a monitor will become available within the compliance timeframe of the proposed rules. A number of tasks remain to be completed before the existing Hg CEMS (all of which measure total Hg) can be deemed sufficiently accurate and reliable for use in the proposed regulatory programs.

Response:

At least two current monitoring technologies can accurately monitor speciated Hg emissions. The Agency will continue to test speciated Hg monitoring technologies. If these technologies are adequately demonstrated, the Agency may consider a proposed rulemaking within four to five years after program implementation, which should provide enough lead time for development and installation of these monitoring systems. The final rule requires the measurement of total vapor phase Hg, but does not require separate monitoring of speciated Hg emissions (i.e., elemental and ionized Hg). Because of the potential impact of Hg speciation on local versus broader geographical deposition, the Agency considers separate monitoring of these emissions as a need to be addressed.

C. EPA's Proposed Revised Benefits Assessment

General Comments concerning EPA's Proposed Revised Benefits Assessment

Comment:

The commenter (OAR-2002-0056-5460) agreed that EPA should improve its estimate of human exposure to Hg that arises from power plant emissions. The commenter stated that two notes of caution must be sounded, however.

The commenter stated that first, the proposed revised benefits assessments methodology described in the NODA will not cure the fundamental defects in the proposed CAMR. The commenter pointed out that, for example, the revised methodology does not address, let alone remedy, EPA's failure to calculate a proper Section 112 MACT floor. And, the commenter added, as long as EPA continues to underestimate the benefits associated with a proper Section 112 approach, it will continue to overestimate the comparative benefits of its proposed Section 111 approach. The commenter, therefore, reiterated that EPA should focus its energies on remedying the problems with its Section 112 proposal.

The commenter further stated that second, EPA cannot and should not delay regulation until all alleged scientific uncertainties concerning power plant Hg emissions have been resolved. The commenter stated that, to the contrary, to the extent uncertainties exist concerning Hg speciation, deposition, transport and exposure, EPA should err on the side of caution so as to fulfill the preventive and precautionary purposes of the Clean Air Act. See American Lung Ass'n, 134 F.3d at 389; Lead Industries Ass'n, 647 F.2d at 1155; see also 42 U.S.C. § 7412(d)(2) (requiring EPA to impose emissions standards that "require the maximum degree of reduction in emissions. . ."). The commenter added that, furthermore, as previously noted, EPA is required to regulate power plant emissions promptly.

Response:

EPA appreciates the commenters concerns. EPA is finalizing a cap-and-trade approach under section 111. Please see the Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units and the Removal of Coal- and Oil-fired Electric Utility Steam Generating Units from the Section 112(c) List for a discussion of the Agency's rationale for not proceeding under Section 112. For a discussion of our exposure modeling, please see the Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls and the Regulatory Impact Analysis in the docket.

Comment:

With regard to the first three steps of the proposed revised benefits assessment methodology, the commenter (OAR-2002-0056-5460) reiterated that EPA should not allow any alleged uncertainties in the scientific evidence to prevent it from regulating power plant Hg emissions in a manner adequate to protect human health and the environment. The commenter stated that existing science confirms the need to regulate power plant emissions and any scientific uncertainties should be resolved in favor of more protective requirements.

Response:

EPA is finalizing a cap-and-trade approach under section 111. Please see Chapters 10 and 11 of the CAMR Regulatory Impact Analysis for a discussion of the exposure modeling and benefit methodologies used to analyze the benefits associated with this rulemaking.

Comment:

Two commenters (OAR-2002-0056-5365, -5404) supported EPA's proposed general methodology for revising its assessment of the benefits associated with Hg emissions reductions from power plants. The commenters believed that the revised benefits assessment methodology generally is an appropriate, reasonably accurate quantification of benefits associated with the implementation of EPA's proposed regulation of Hg emissions (See 69 Fed. Reg. 69864, 69872.). In particular, the commenters supported EPA's revised methodology insofar as it focuses on quantification of benefits from Hg reductions (See 69 Fed. Reg. at 69873.). According to the commenters, that is, the Agency's requests for further comment in the NODA indicate that EPA's benefits analysis appropriately has shifted toward issues that are central to the purpose of the Hg regulation, in particular, changes in human exposure to Hg as a result of the emissions reductions that will be required by the rule, and potential consequent changes in public health (See 69 Fed. Reg. at 69876.).

The commenters stated that by contrast, EPA's benefits assessment in the NPR dated Jan. 30,2004, as well as EPA's conclusion that the benefits of the proposed rule far outweigh the costs, was essentially faulty and misleading in that the assessment and its consequent conclusions were premised on tangential and/or irrelevant information. According to the commenters, for example, in the NPR dated January 30,2004, EPA predicted that the implementation of Hg MACT would result in benefits equal to $15 billion which would be offset by costs equal to less than $2 billion—a net benefit valued at greater than $13 billion. The commenters stated that EPA's figures are misleading, however, because none of the quantified benefit is attributable to EPA's proposed Hg regulation. According to the commenters, rather, the benefit reflects ancillary NO_x and SO_2 reductions expected to be achieved as co-benefits resulting from the operation of MACT-imposed Hg controls. The commenters stated that in any event, according to EPA, "most or all of the ancillary benefits of control would be achieved anyway, regardless of whether a section 112 MACT is promulgated." See 69 Fed. Reg. at 4711 ("[E]ven if no [mercury] controls were imposed [pursuant to the rule-making], most major coal-fired units would have to reduce their SO_2 and NO_x emissions as part of the effort to bring the nation into attainment with new air quality standards."). According to the commenters, considering the foregoing, EPA's benefits assessment in the NPR is of limited value, because it quantifies only benefits that are ancillary to the core purpose of the proposed rule and are likely to be realized in any case. The commenters believed that it is fundamentally inappropriate to justify a rule—as EPA did in the NPR—based on emissions reductions that are not related to the central purpose of the rule and that are likely to occur whether or not the rule is promulgated. Thus, in response to EPA's requests for comment regarding the revised benefits assessment, the commenters strongly believed that the Agency must focus on quantifying benefits that are central to the purpose of the regulation.

As such, the commenters supported the overall methodology outlined in the NODA,

which will enable EPA to assess the potential public health benefits associated with reducing Hg emissions from power plants, i.e., the benefits to public health that are related to the purpose of this rule. According to the commenters, such quantification is admittedly difficult, as there is no direct correlation between power plant Hg emissions and human MeHg exposure (which, as EPA recognizes, is the public health outcome of concern). As such, the commenters concurred with EPA that the Agency must undertake the following five-step assessment in order to translate power plant Hg emissions reductions into public health outcomes: (I) quantify Hg emissions projected from power plants under the Base Case as compared to after implementation of the Hg rule, including quantifying Hg emissions that result from sources other than U.S. coal-fired plants; (ii) model changes atmospheric dispersion, atmospheric speciation, and Hg deposition as a result of Hg reductions from power plants; (iii) model the link between changes in Hg deposition and changes in MeHg concentrations in fish; (iv) assess types and amounts offish consumed by U.S. customers and extrapolate resulting changes in MeHg exposures resulting from reduced power plant Hg emissions; and (v) assess how reductions in MeHg exposure affect human health.

Although the commenters supported the overall methodology EPA has articulated, and concurred that the Agency has properly identified the five necessary steps to enable quantification of the public health benefits associated with the proposed rule, the commenters also supported the concerns articulated by the Electric Power Research Institute ("EPRI") and others with respect to specific aspects of how EPA proposes to conduct specific aspects of the benefits assessment. For example, the commenters concurred with EPRI that there are some significant weaknesses in how the MMAPs model quantifies the link between changes in Hg deposition and changes in MeHg concentrations in fish. The commenters urged EPA to seriously consider these critiques of specific aspects of the benefits assessment before it finalizes this analysis.

Response:

The benefits analysis completed for the RIA is not intended to model local-scale changes in fish tissue concentrations and exposures in support of site-specific risk analysis. Instead, modeling conducted for the RIA is intended to capture generalized regional changes in methlmercury exposure resulting from reductions in power plant mercury emissions in order to support a national-scale benefits assessment focusing on the 37 state eastern US study area. For additional details on the benefits analysis modeling framework see Section 10 of the RIA.

EPA recognizes the complexities associated with methylation of mercury deposited in waterbodies and watersheds and subsequent biomagnification within the aquatic foodweb. While there are dynamic fate/transport models that can be used to conduct detailed site-specific modeling of mercury in aquatic and terrestrial environments for purposes of predicting mercury fish tissue concentrations (e.g., the dynamic mercury cycling model), it is not feasible to utilize these resource-intensive models for a regional- or nationals-scale analysis. Therefore, EPA selected the MMAPs models for application in the RIA. EPA fully recognizes the limitations and simplifying assumptions associated with this model, but believes that it has sufficient precision to support a benefits analysis conducted at the regional- or national-scale (i.e., it can capture

general trends in mercury fish tissue response to changes in mercury deposition from power plants). However, to provide additional perspective on the relationship between mercury deposition and fish tissue concentration changes (especially in relation to MMAPS linearity assumption and the lag time required for systems to reach steady state), EPA has conducted several detailed local-scale sensitivity analyses. The results of these case studies are presented and discussed in Appendix D.

The RIA includes an assessment, to the extent possible given our scientific understanding of mercury and its behavior in the environment and impacts on human health, of the health benefits associated with the proposed regulatory options. Due to limitations in our current understanding of these technical areas related to mercury this benefit analysis is limited to the self-caught freshwater fish consumption pathway and to IQ deficits in prenatally-exposed infants. In keeping with precedent in evaluating benefits of air regulations (REFERENCE), co-benefits (in this case resulting from potential reductions in direct PM2.5) are also included in the RIA.

Comment:

One commenter (OAR-2002-0056-5535) referenced EPA's Revised Benefits Methodology Must Account Fully for the Risks and Public-Health Costs of Hg Pollution

EPA's NODA seeks public comment on a suite of technical issues, supposedly to assist the agency in developing its final assessment of the benefits of Hg control pursuant to Executive Order 12866. Specifically, EPA asks for public input on "the U.S. power plant contribution to total Hg deposition within the U.S.," the agency's planned approach to "evaluate how Hg moves through the atmosphere and how it ultimately will be deposited," "the strengths and weaknesses of different approaches for modeling the anticipated response offish tissue [MeHg] concentrations to declines in deposition," the "consumption data" to be used in EPA's "analysis concerning the relationship between reductions in MeHg concentrations in fish tissue and reductions of human exposure to MeHg," and "all aspects of the methodology for estimating the relationship between reductions in MeHg exposure and improvements in health."

These sweeping requests for information suggest that EPA is interested in more than simply calculating the benefits of a Hg control regime. Instead, the agency appears to be giving the utility industry another chance to advance claims that power plants are neither a significant cause of U.S. Hg deposition nor a public health concern, and to argue that EPA should weaken its proposed Hg rule before finalizing it. Indeed, EPA acknowledges that this information may be used to influence the stringency of the final rules, saying:

> "To the extent that we receive any comments or other information in the process of completing the benefits assessment for purposes of EO12866 and to the extent that such information bears on the statutory factors relevant to setting either a beyond-the-floor standard for Hg under CAA Section 112(d) or a standard of performance for Hg under CAA Section 111, we intend to evaluate and consider that information as we make a final decision as to which regulatory approach to pursue."

This open-ended invitation for comment reveals how far EPA has veered from its statutory responsibilities under § 112 of the Act. At this stage of the rulemaking process, the agency should be refining its understanding of the issues central to the development of a proper MACT standard by correcting the problems created by its proposal to subcategorize by coal rank, by abandoning its inflation of the emission standards to account for "variability," by making an unbiased assessment of the state of Hg control technology in light of manufacturers' comments, and by conducting the modeling (and additional technical work) necessary to evaluate the cost, energy impacts, and non-air quality impacts of numerous above-the-floor control options. Outrageously, EPA instead seeks to revisit issues considered four years ago when the agency concluded that regulating power plants' hazardous air emissions was "appropriate and necessary," and gives the public a mere month to make–again–the scientific case for stringent controls on utility units.

Response:

EPA is finalizing a cap-and-trade approach under section 111. Please see Chapters 10 and 11 of the CAMR Regulatory Impact Analysis for a discussion of the exposure modeling and benefit methodologies used to analyze the benefits associated with this rulemaking.

1. Step 1: Analyzing Hg Emissions from Other Sources. EPA plans to do fate and transport modeling of emissions originating in other countries to allow an estimated of U.S. power plant contribution to total Hg deposition in the U.S. EPP received comments relevant to this issue from the Center for Energy and Economic Development (OAR-2002-0056-2256), Electric Power Research Institute (OAR-2002-0056-2578), Hubbard Brook Research Foundation (OAR-2002-0056-2038), National Mining Association (OAR-2002-0056-2434), TXU Energy (OAR-2002-0056-1831), and Utility Air Regulatory Group (OAR-2002-0056-2922). Some of these comments used different approaches for stimulating boundary conditions for apportioning Hg exposure from domestic and international sources, and EPA asks for input on these alternative approaches and analyses.

Comment:

One commenter (OAR-2002-0056-5458) noted that EPA requested that stakeholders identify sources of Hg emissions other than coal fired utilities for inclusion into the IPM. The lack of Hg source data in the 1999 National Emission Inventory (NEI) is a direct result of the Agency's decision not to include hazardous air pollutants in its Consolidated Emission Reporting Rule. Other source categories not regulated for Hg emissions include sewage sludge incineration and Portland cement plants that burn coal. Of combustion sources, coal fired utilities make up half the Hg emitted in New York State. The Department has promulgated and implemented more stringent state regulations that contain stricter emission limits for Hg emissions for the municipal waste combustion source category than promulgated by the EPA. The current estimated Hg emissions inventory for stationary sources in New York is attached as Table 1 (see

OAR-2002-0056-5458). The Department is evaluating other source categories for reductions and hopes that EPA will propose a NESHAP for the utility sector that will provide meaningful reductions of national Hg emissions.

Resources:

EPA appreciates the additional information submitted by the commenter. EPA is finalizing a cap-and-trade approach under section 111. Please see Chapter 8 of the CAMR Regulatory Impact Analysis for a discussion of the air quality modeling for the CAMR regulatory options and the resulting change in mercury deposition.

Comment:

One commenter (OAR-2002-0056-5488) stated that studies from the Florida Everglades and Wisconsin, as well as the heterogeneity among the states in Hg deposition highlight the localized nature of Hg deposition. Any benefits estimation must model local deposition, methylation, and the consumption of fish contaminated by such local deposition, whether that consumption occurs locally or more nationally. The NODA refers to the EPA's intent "to estimate the U.S. power plant contribution to total Hg deposition within the U.S." From a public health perspective, this estimate is meaningless, as Hg deposition, methylation, and human exposure from U.S. coal-fired power plants depend on highly localized conditions and are unrelated to the U.S. fraction of total Hg deposition averaged over the entire U.S. land mass.

Response:

Please see Chapter 3 of the CAMR Regulatory Impact Analysis for a detailed discussion of mercury in the environment, including an assessment of the response time for systems after a change in mercury deposition. Please also see Section 8 for a discussion of the change in mercury deposition based on air quality modeling and Chapters 11 for a benefits analysis of the CAMR.

Comment:

One commenter (OAR-2002-0056-5535) presented several specific issues below that would benefit from such careful peer review. They did not intend this list to be comprehensive, but merely included it to illustrate that the agency must address critical scientific issues prior to making changes to its deposition and watershed models or conducting other components of the proposed analyses. This overview serves to demonstrate that it would be foolish to hold up final Hg regulations while EPA further investigates certain technical issues concerning the emissions, fate, and toxicity of Hg from power plants.

- Global model of Hg transport. The global model of Hg transport developed by the Electric Power Research Institute needs thorough vetting by the broader scientific community before it, or results generated by it, are adopted by the EPA. In particular, the spatial resolution of EPRI's model is coarse and the effect of that resolution profoundly affects the modeling results.

Response:

EPA appreciates the commenters input. EPA is finalizing a cap-and-trade approach under section 111. Please see Chapter 8 of the Regulatory Impact Analysis for a discussion of the air quality modeling used to analyze the CAMR rule.

Comment:

One commenter (OAR-2002-0056-5423) notes that natural sources of Hg emissions dominate the small amount of Hg emissions from U.S. power plants. This commenter believes that this fact brings into stark reality that any meaningful control of Hg emissions toward a realistic "reduction" in Hg deposited on U.S. soils will be almost impossible. There are well over 5,000 surface and submarine volcanoes in the world, with about 50 to 60 eruptions each month, according to the Smithsonian Institution. Volcanic degassing may be the single largest source of ocean and atmospheric Hg. For example, at Roaming Mountain, Wyoming, researchers measured Hg emanating from the clay hillside at up to 2,400 nanograms per square meter per hour. By comparison, background levels away from geothermal areas range from zero to ten. So Hg emissions from active geothermal areas could be tens and hundreds times more than from other background areas.

For obvious reasons, volcanic degassing and other geothermal activities as dominant sources of Hg have not received much attention or have been downplayed. For example, EPA staff provided the Administrator with an outdated volcanic accounting study. Figure A1 (see OAR-2002-0056-5423) clearly shows that EPA's current adopted value for the annual contribution of atmospheric Hg by volcanic eruptions and degassing is significantly under accounted for by about a factor of 6 to 7. When adjusted to reflect a more accurate accounting of volcanic Hg emission (Figure A2, see OAR-2002-0056-5423), U.S. power plant contributions to the annual estimated Hg budget world-wide fall to an insignificant 0.8 percent or less.

Figure A3 (see OAR-2002-0056-5423) maps the range of potential volcanic activity in the Western U.S. These are also potential sources of enormous Hg degassing and deposition, especially Yellowstone National Park.

Figure A4 (see OAR-2002-0056-5423) emphasizes that the pools of Hg stored in U.S. forests and peat lands (covering less than 2 percent of U.S. area) swamp the 100-150 tons total annual anthropogenic Hg emission from U.S. sources.

Taken together, these figures support EPA's admission of poor accounting for (a) natural sources of Hg emission and (b) the large pool of background Hg at all times available for emission from the natural ecosystems and geological settings within the U.S.

Yellowstone National Park is just one such geological reservoir of Hg. A report issued last fall by the Idaho National Engineering and Environmental Lab showed that several places in Yellowstone Park have higher levels of airborne Hg than power plants. It went on to say that Yellowstone could emit or exceed as much Hg as all of Wyoming's eight coal-fired power plants

combined.

At Yellowstone Lake, researchers have discovered submerged faults, explosion craters, domal features, hydrothermal vents, lava flows extending far out into the lake and much more. Mercury may propagate from these natural features up through the food chain transforming into MeHg in native cutthroat trout.

And since Yellowstone is the headwaters of important tributaries to the Missouri (Yellowstone River) and Columbia (Snake River), no one knows how far the natural contamination carries through the Earth's air and water systems.

However, the Hg presence and emissions were noted by experts to pose no danger to park rangers or visitors. Even native grizzly bears who consume up to 400 lb of spawning cutthroat trout exhibit no ill effects, according to researchers with the Interagency Grizzly Bear Study Team.

Thus, the most important question for EPA's Hg emission and deposition modeling team to answer confidently is whether the proposed CAMR to control Hg emissions from U.S. power plants can assure any consequential "reduction" of Hg deposition in U.S. soils, leading to any reputed public health "benefits."

Response:

Please see Chapter 3 of the CAMR Regulatory Impact Analysis for a detailed discussion of mercury in the environment, including an assessment of the response time for systems after a change in mercury deposition. Please also see Section 8 for a discussion of the change in mercury deposition based on air quality modeling and Chapters 11 for a benefits analysis of the CAMR.

Comment:

One commenter (OAR-2002-0056-5423) provides an important challenge for EPA's Hg emission and deposition modeling team (Figure B1, see OAR-2002-0056-5423). It shows the results from recent measurements of Hg content in Illinois soils clearly suggesting that atmospheric deposition from any past or current U.S. power plants is insignificant compared to the large quantity of background Hg already resided in soils across the state. This is why it is extremely difficult for EPA to convincingly show that the Hg from U.S. power plant emissions will be selectively filtered by the ecosystem components in Illinois (or anywhere else) to bring about increased levels of MeHg in freshwater fish while ignoring the large pool of natural Hg in the native ecosystem. It is therefore extremely difficult, if not impossible, for EPA to plausibly demonstrate the assertion that its proposed CAMR can/will bring about any direct, measurable improvement in public health.

In Figure B2 (see OAR-2002-0056-5423), the commenter provides a recent Hg emission and deposition budget analysis for the northeastern Chinese city of Changchun. Scientists found

that of that 7.1 tons of Hg emitted by the city of Changchun, only less than 12 percent of coal-fired power plant Hg was deposited back into the local area, while most escaped as contributions to regional and global cycling of Hg.

This scenario of the local Hg emission and deposition budget at Changchun, China may serve as a useful model verification target for the EPA's Hg emission and deposition modeling team under a wide range of meteorological and climatic conditions and settings.

Man-made atmospheric deposition of Hg is a very small contributor to the huge amount of natural Hg in Illinois and U.S. soils

(1) It has been estimated that "anthropogenic activities could have increased world soil Hg content by [only] 0.02 percent."

(2) From the measured high Hg content in Illinois soils, it would take 9000 years at the currently measured atmospheric deposition rate to dump all the Hg to the top 380-cm of Illinois soils.

(3) If assuming the average Hg in the top 140-cm of U.S. soils to be about 10 ppb, it would take 14,000 years at the current atmospheric deposition rate to do it.

Response:

EPA appreciates the commenters input. Please see Chapter 3 of the CAMR Regulatory Impact Analysis for a detailed discussion of mercury in the environment, including an assessment of the response time for systems after a change in mercury deposition. Please also see Section 8 for a discussion of the change in mercury deposition based on air quality modeling.

Comment:

One commenter (OAR-2002-0056-5423) presents an important observational target for EPA's modelers (Figure C1, see OAR-2002-0056-5423). First, it is important to point out that the Hg in rainwater or moist air exists mostly in the dissolved ionic form of Hg (Hg^{2+}) rather than MeHg–the biologically active form of Hg that may affect human health at extraordinary dose levels. Figure C1 (see OAR-2002-0056-5423) shows that most (72.5 percent) of the MeHg in the Chesapeake Bay ecosystems comes from *in-situ* production. Remote transport of MeHg from rivers contributes about another 20 percent, and atmospheric deposition sources may contribute toward production of as little as 7.5 percent of MeHg in the Chesapeake Bay's ecosystems. Such a scenario of the MeHg budget clearly emphasizes the need for better scientific understanding of the complex physical, chemical and biological factors controlling the production *and destruction* of MeHg, and why the levels of MeHg in an ecosystem *do not* depend directly on available amounts of inorganic Hg (i.e., from background or power plant emissions).

Sources of MeHg in the Chesapeake Bay: Atmospheric deposition is a not an important contributor Percentage contribution of 70 percent MeHg sources 60 percent in the Chesapeake

Bay In-situ Production Rivers Atmospheric Deposition Reference: Mason et al. (1999)

Response:

EPA appreciates the commenters input. Please see Chapter 3 of the CAMR Regulatory Impact Analysis for a detailed discussion of mercury in the environment, including an assessment of the response time for systems after a change in mercury deposition. Please also see Section 8 for a discussion of the change in mercury deposition based on air quality modeling.

Comment:

The commenter (OAR-2002-0056-5460) stated that UARG, following EPRI, argues that Hg pollution is a global problem and, therefore, EPA should not regulate Hg emissions pursuant to Section 112. See UARG Comments at 25-26. The commenter noted that, in particular, UARG contends that only 25 percent of domestic Hg deposition stems from domestic anthropogenic sources. Id. (citing EPRI Comments at 13). But little, the commenter stated, if any, basis exists to have confidence in UARG's estimates given EPA's conclusion that Hg's fate in the environment can not be tracked with precision and that Hg emitted from any source may be re-emitted into the environment. See 69 Fed. Reg. 4652, 4658 (Jan. 30, 2004). The commenter stated that indeed, UARG itself contends that "the state-of-the-science on Hg cycling is too imprecise to predict" the consequences of changes in Hg deposition. UARG Comments at 26 n.57.

The commenter stated that, more importantly, even if UARG is correct that Hg is a global problem, it does not follow that EPA should not regulate domestic power plant emissions pursuant to section 112. The commenter further stated that to the contrary, the Court of Appeals for the D.C. Circuit has already made clear that whether a pollutant has local, regional or global consequences is not, standing alone, a sufficient legal basis for concluding that the pollutant should not be regulated. See American Lung Ass'n, 134 F.3d at 392 (rejecting EPA's argument that it could avoid revising a national ambient air quality standard simply by claiming that the pollutant at issue had local effects only). The commenter added that simply because EPA cannot prevent Hg from entering the U.S. from other countries is not a reason for EPA to avoid regulating domestic Hg emissions. The commenter stated that UARG's argument that local emissions should be exempt from regulation because they cause only part of the problem makes no sense: Just because pollution enters our borders from somewhere else is not a reason to allow domestic sources to create even more pollution. The commenter further stated that, indeed, it is well-established that a polluter may be enjoined from contributing to a public nuisance even where the polluter's contributions alone are insufficient to create the nuisance. See, e.g., The Law of Torts § 52 ("Pollution of a stream to even a slight extent becomes unreasonable when similar pollution by others makes the condition of the stream approach the danger point."); Cox v. City of Dallas, 256 F.3d 281,292 n.19 (5th Cir. 2001) (explaining that nuisance liability attaches where one simply contributes to the nuisance); City of New York v. Beretta U.S.A. Corp., 315 F. Supp. 2d 256, 282 (E.D.N.Y. 2004) ("Where it is difficult or impossible to separate the injury caused by one contributing actor from that caused by another and where each

contributing actor's responsibility individually does not constitute a substantial interference with a public right, defendants may still be found liable for conduct creating in the aggregate a public nuisance if the suit is one for injunctive relief").

The commenter stated that at bottom, EPRI and UARG appear to be arguing that EPA needs greater proof that power plant Hg emissions cause harm before it can regulate those emissions. But, the commenter stated, no reason exists for EPA to allow harm from Hg emissions to continue until it has yet more concrete proof of that harm. The commenter further stated that to the contrary, existing science already confirms the harm is sufficient for EPA to act. The commenter stated that, finally, given the overarching flaws in EPRI's and UARG's comments, EPA should look with skepticism upon their more detailed technical claims.

Response:

EPA appreciates the commenters input. Please see Chapter 3 of the CAMR Regulatory Impact Analysis for a detailed discussion of mercury in the environment, including an assessment of the response time for systems after a change in mercury deposition. Please also see Section 8 for a discussion of the change in mercury deposition based on air quality modeling.

Comment:

One commenter (OAR-2002-0056-5497) stated that any emissions inventory must do a good job of defining the global sources of Hg emissions. Recent modeling by EPRI and others has revealed that a substantial majority of Hg that is deposited in the U.S. (about 75 percent) originates from natural sources and anthropogenic sources outside the U.S. Asian sources may provide 20 percent of the Hg deposited in the U.S. EPRI's NODA comments (see OAR-2002-0056-5469) offer a number of sources of information on global Hg emissions.

Modeling of Hg emissions from global and domestic sources remains a challenging exercise. To date, Hg model results have not matched the levels of Hg in water bodies and fish in various parts of the U.S. The atmospheric chemistry of Hg may hold the key to this disparity. As EPRI notes in its NODA comments, atmospheric Hg reactions can move in different directions. For major urban sources, including mobile sources, elemental Hg can be rapidly oxidized to ionic Hg which can then be removed form the atmosphere by wet and dry processes. By contrast, ionic Hg emitted from coal-fired power plants appears to be reduced to elemental Hg shortly after leaving the stack. Recent results from Edgerton suggest that models that do not account for this atmospheric reduction of ionic Hg will over predict the local and regional Hg deposition from coal-fired power plants.

Future EPA modeling should use the results of global modeling to define the boundary conditions for domestic modeling. Global modeling is a better scientific approach for setting boundary conditions than arbitrarily setting those conditions. If EPA uses the results of global modeling to set boundary conditions, it should still review those results to ensure they are reasonable.

Response:

EPA appreciates the commenters input. Please see Chapter 3 of the CAMR Regulatory Impact Analysis for a detailed discussion of mercury in the environment, including an assessment of the response time for systems after a change in mercury deposition. Please also see Section 8 for a discussion of the change in mercury deposition based on air quality modeling.

2. Step 2: Analyzing Air Dispersion Modeling Capabilities. EPA plans on modeling the atmospheric dispersion, atmospheric speciation, and deposition of Hg using the REMSAD and CMAQ models, with the GEOS-CHEM global model for boundary conditions input. The simulated results will be compared with ambient monitoring data from the Mercury Deposition Network (MDN). EPA requested comments on the use of these models and approach. EPA received comments on the use of models for assessing the impacts of the proposed programs on Hg deposition patterns from the Center for Energy and Economic Development (OAR-2002-0056-2256), Clean Air Task Force et al (OAR-2002-0056-3460), Electric Power Research Institute (OAR-2002-0056-2578), and Utility Air Regulatory Group (OAR-2002-0056-2922). EPA also sought comment on the alternative approaches suggested by some of these commenters.

Comment:

One commenter (OAR-2002-0056-5464) highlighted another concern related to EPA's proposed rule, which is the issue of hot spots. The commenter believed the definition of a "hot spot" in the proposal is insufficient. The proposal states, "a power plant may lead to a hot spot if the contribution of the plant's emissions of Hg to local deposition is sufficient to cause blood Hg levels of highly exposed individuals near the plant to exceed the RID" (69 Federal Register 4702). The commenter was very concerned that the proposal considers the effects of only one plant at a time in determining if there is a hot spot. This method of determining hot-spots ignores the cumulative, localized impacts of Hg deposition caused by multiple, nearby or co-located, coal-fired utility boilers by individually quantifying and analyzing the air quality impact of each boiler in the absence of the others. This is contrary to previously adopted, long-standing, peer-reviewed EPA procedures for performing air quality modeling on stationary sources for criteria pollutants and is not acceptable for performing air quality modeling for more hazardous pollutants like Hg.

The commenter had an additional concern related to the improvement of existing hot spots and stated that 45 states have issued fish consumption advisories due to Hg. Clearly a contaminated water body is a hot spot that already exists. In fact, the current situation indicates that we have "hot states" and "hot regions" and not just localized hot spots. The commenter feared that EPA's proposal, which calls for a nationwide market-based cap-and-trade program, will not ameliorate the problem of existing hot spots or areas.

The commenter categorically disagreed with UARG's position and strongly urged EPA, if the agency decides to proceed with a rule under Section 111, to maintain the ability of state and local agencies to opt out of the trading program.

The Clean Air Act explicitly allows state and local air pollution control agencies to adopt programs more stringent than those of the federal government. Specifically, section 116 states that air quality agencies are not precluded from adopting or enforcing any standards, limitations or requirements as long as they are at least as stringent as those required under the federal program. The only exceptions are found in section 119 of the Clean Air Act, which preempts certain state and local regulation of mobile sources. Therefore, UARG's suggested approach, in which EPA would preempt state and local agencies' ability to adopt a more stringent program that does not permit trading, is in direct conflict with section 116 of the Clean Air Act.

The commenter stated that for a variety of reasons, maintaining the ability of state and local agencies to adopt more stringent programs is essential. Not the least of these reasons is that state and local agencies will need some way of addressing and preventing hot spots in their areas. In fact, EPA appropriately acknowledged this in its January 30, 2004, proposal by stating, "[s]tates retain the power under the proposed section 111 rule to adopt stricter regulations to address local hot spots or other problems" (69 Federal Register 4702).

UARG expresses concern in its comments that allowing states to opt out of the program would result in a "patchwork approach". The commenter contended that a federal standard, such as what EPA has proposed, that is less stringent than the law requires would be to blame for any patchwork effect. In fact, state and local agencies have already begun to adopt their own programs to ensure adequate public health protection in their states (see attached table). If EPA and industry wish there to be more national consistency, EPA can accomplish this by adopting a protective standard consistent with the requirements of Section 112(d). Fewer state and local agencies may then feel compelled to adopt different approaches (see OAR-2002-0056-5464).

Response:

EPA has examined the commenter's concerns in context of the final rulemaking. EPA is finalizing a cap-and-trade approach under section 111. EPA has addressed the hot spots issue in the Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units and the Removal of Coal- and Oil-fired Electric Utility Steam Generating Units from the Section 112(c) List for a discussion of the Agency's rationale for not proceeding under Section 112 Notice and in the Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls in the docket.

Comment:

One commenter (OAR-2002-0056-5559), beginning in 2001, began a two-year effort to develop a Hg atmospheric modeling system for Wisconsin and the Great Lakes region. Partial

funding for this work was provided by a grant, #X97599601, from EPA.

Based on this experience, the commenter had the following comments on the modeling of Hg deposition that EPA is proposing to conduct as part of the revised benefits assessment.

Step 1–Analyzing Mercury Emissions from Other Sources. The commenter used 1999 National Emission Inventory (NEI) to build emissions estimates for Hg and conducted considerable quality assurance of the Hg emissions data. Based on experience with the 1999 NEI Hg emissions data, if EPA chooses to use the 2002 NEI data, this commenter recommends that EPA conduct considerable quality assurance of these data, before they are used in model simulations.

In simulations, the commenter added Canadian and Mexican emission sources. Although those data are somewhat incomplete, the commenter would be happy to share these data with EPA.

Step 2–Analyzing Air Dispersion Modeling Capability. There is a significant amount of uncertainty associated with the simulation of Hg deposition. EPA should conduct an uncertainty analysis with the modeling system to evaluate the effect on the modeling simulations for changes to the underlining assumptions in the model. In particular, EPA should evaluate changes to the wet deposition algorithms, dry deposition algorithms and emissions speciation profiles and processes that form MeHg in water bodies.

There is some anecdotal evidence such as around the White Pine smelter in Michigan and around certain Florida point sources, that reductions in Hg emissions at large sources results in a reduction in Hg concentration in nearby water bodies. To date, this phenomenon has not been satisfactorily simulated with Eulerian grid models. EPA should further investigate this phenomenon, since it seems to highlight a significant problem with the current state of the science Hg modeling systems and puts into doubt the interpretation of the results of model simulations. If a significant improvement in nearby water quality results from a reduction in Hg emissions, this commenter will realize a much greater benefit from power plant Hg reductions than has been demonstrated by previous model simulations.

EPA should reconsider its selection of the Regional Modeling System for Aerosols and Deposition (REMSAD) for one of the models to use in its analyses. Under a grant, AER and Environ worked with the commenter to create a version of the Comprehensive Air Quality Model with extensions (CAMx) that includes the most up-to-date Hg chemistry and deposition algorithms. The model development and simulations were peer reviewed by Alpine Geophysics. When measured wet deposition at Mercury Deposition Network (MDN) sites was compared with model results, the commenter found that CAMx provided much better model performance than REMSAD.

Deposition is very sensitive to rainfall simulation in MM5. Since, in the eastern U.S., a significant portion of annual Hg wet deposition occurs in convective rain events, it is important to properly simulate convection in the meteorological model. In model performance testing for

MM5, the commenter found that using a 12 Km grid spacing rather than 36 Km, 46 vertical layers rather than 34, and the Reisner Graupel Ice scheme rather than Simple Ice provided superior performance for a convective rainfall event in the Great Lakes area. These changes will adversely affect model run time, but may be worth employing for comparison purposes.

Response:

Please see Chapter 3 of the CAMR Regulatory Impact Analysis for a detailed discussion of mercury in the environment, including an assessment of the response time for systems after a change in mercury deposition. Please also see Section 8 for a discussion of the change in mercury deposition based on air quality modeling.

Comment:

The commenter (OAR-2002-0056-5563) wished to specifically address the issue of utilizing modeling under the notice of data availability for the Clean Air Mercury Rule. The commenter felt that modeling should only compliment a comprehensive monitoring program of Hg pollution. Monitoring should not be limited to the Great Lakes and Eastern portion of the country-it should be extended to all parts of the U.S., especially to tribal lands and communities. The utilization of the Community Multiscale Air Quality (CMAQ) and Regional Modeling System for Aerosols and Deposition (REMSAD) models that the EPA had used and intended to use in the future for modeling the atmospheric dispersion, speciation, and deposition of Hg did not address tribal concerns effectively. The EPA's plan was to use a 36-kilometer modeling grid for both CMAQ and REMSAD in assessing the aforementioned items. However, these models were equipped to handle 12 and 4-kilometer modeling grids. In order to assess the real effects of Hg on tribal lands, the commenter urged the EPA to utilize the latter modeling grids. This rational was related to the size of tribal lands and communities. Most tribes occupied land closer to these grid sizes. Furthermore, the proportion of the proposed models for both CMAQ and REMSAD models failed to distinguish between different jurisdictions such as tribal, state, and county lands. This issue failed in carrying out the trust responsibility of the federal government. Tribal lands, as sovereign Nations, had the right to be indicated as such in modeling practices. In addition, the NTAA also feels that proposed modeling techniques will error in properly addressing jurisdictional point sources of Hg. Therefore, modeling output could be adversely affected.

Response:

Please see Chapter 3 of the CAMR Regulatory Impact Analysis for a detailed discussion of mercury in the environment, including an assessment of the response time for systems after a change in mercury deposition. Please also see Section 8 for a discussion of the change in mercury deposition based on air quality modeling and Chapters 11 for a benefits analysis of the CAMR.

Comment:

One commenter (OAR-2002-0056-5458) agreed with the subcategorization of coal types for regulatory purposes in response to the NODA section II.C.3.b., but disagrees with the standard (or average) speciation profile in modeling analysis. Work conducted by the Department on the 1999 Information Collection Request (ICR) shows that the majority of Hg emitted in the eastern half of the US is predominantly in the oxidized form. The speciation profile cited in the NODA, 54 percent elemental, and 43 percent oxidized and 3 percent particulate Hg, is a national average and does not represent the Northeast States potential deposited burden. The Department's analysis of the ICR data indicates a profile closer to 30 percent elemental, 65 percent oxidized and 5 percent particulate Hg for sources which are impacting New York.

The NODA focuses on industry sponsored research about the speciation of atmospheric Hg after it exits the stack and how emissions rapidly converted to elemental Hg in the plume will not be deposited in the U.S. due to their long atmospheric residence time (Air Docket OAR-2002-0056-2928 and OAR-2002-0056-2848). This entire data set was not included in the docket and the Department could not locate any information which indicates the data had undergone any public and peer review. The EPA must cautiously evaluate the results and conclusions drawn from this research in light of the unknown and non-linear relationship between Hg emissions and deposition. There are many factors which need to be assessed when evaluating atmospheric Hg transformation and potential deposition scenarios. The NODA must consider the emerging science about the atmospheric chemistry and deposition of Hg. These recent findings indicate that the abundance of oxidized Hg increases with altitude in the troposphere, and airborne halogens and oxidants, such as ozone facilitate the oxidation of elemental Hg, which in turn increases both wet and dry deposition of Hg. The reactions are occurring in areas with high seasonal ozone levels and also appear to take place in the temperate coastal zone. Researchers have concluded that a short half-life for elemental Hg is probable.

Response:

EPA appreciates the commenters concerns. Please see EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005) for a discussion of the importance of speciation for mercury capture. Also, please see Chapter 7 of the Regulatory Impact Analysis for a discussion of how we took speciation into account in our power sector modeling and see Chapter 8 for a discussion of how we took speciation into account in our air quality and deposition modeling. Please see Chapter 3 of the CAMR Regulatory Impact Analysis for a detailed discussion of mercury in the environment, including an assessment of the response time for systems after a change in mercury deposition.

Comment:

One commenter (OAR-2002-0056-5425) said their comments were specific to the Community Multiscale Air Quality (CMAQ) and Regional Modeling System for Aerosols and Deposition (REMSAD) models that the EPA has used and intends to use in the future for modeling the atmospheric dispersion, speciation, and deposition of Hg. The EPA is planning to

use 36 kilometer modeling grids for both CMAQ and REMSAD in assessing the aforementioned items although these same models are equipped to handle 12 and 4 kilometer modeling grids. In the interest of assessing the true effects of Hg dispersion, speciation and deposition on tribal lands, the EPA should use the latter modeling grids because most tribes occupy lands closer to these grid sizes as opposed to the former grid size being proposed by the EPA for modeling. Furthermore, the spatial resolution of the gridded output for both the CMAQ and REMSAD models fails to distinguish between different jurisdictions such as tribal, state and county lands. Such a failure could likely cause the models to incorrectly attribute (e.g., mislocate) one jurisdiction's Hg point source to another jurisdiction (such as a tribe's land). This incorrect attribution of a point source could then adversely affect the results of the modeling output. A means for mitigating this problem is to assign a numeric code to the jurisdiction within the grid cell having the dominant contribution to emissions in that cell. This would help the models to produce more accurate results otherwise impossible under current model designs.

Response:

EPA appreciates the commenters input. Please see Chapter 8 of the Regulatory Impact Analysis for a discussion of EPA's air quality modeling analysis. Please also see EPA's Technical Support Document for the Final Clean Air Mercury Rule: Air Quality Modeling.

Comment:

One commenter (OAR-2002-0056-5502) referenced research results reported to U.S. EPA in June 2004 analyzed Hg deposition for a 2004 Base Case emissions inventory and two 2020 scenarios, the proposed Maximum Achievable Control Technology (MACT) rule and the proposed Cap and Trade (C&T) rule. Additional analyses of Hg deposition patterns for 2004 and equivalent patterns under the MACT and C&T rules have now been carried out.

These additional analyses have examined the deposition that would result from utility sources that are projected under MACT and/or C&T to not implement controls specifically to reduce Hg emissions. Mercury emissions from these sources (in addition to all the other utility sources that will be reducing their Hg emissions) are found to have insignificant impacts on nearby and distant deposition patterns for the C&T case, relative to the MACT case. Receiving waters downwind from these locations are calculated to experience no significant additional deposition due solely to these sources individually or as a group not initiating Hg-specific controls. Thus, under EPA and other definitions of utility Hg deposition "hot spots," these particular sources do not in themselves bring about "hot spot" conditions under a C&T rule relative to either a MACT rule or 2004 emissions conditions.

Measurements of speciated Hg in the ambient atmosphere are needed to improve our understanding of the atmospheric fate and transport of Hg. The commenter recommended that the available information on speciated Hg concentrations be used to (1) provide insights on the processes that appear to influence Hg speciation in the atmosphere, (2) evaluate the performance of global and continental models of atmospheric Hg vs. surface and aloft data, and (3) quantify the limitations and possible biases of those models. Those limitations and biases should then be

taken into account when evaluating the potential benefits of Hg emission reductions.

The MDN data are extremely useful to evaluate the ability of models to reproduce the regional patterns of Hg wet deposition. The MDN data have also highlighted the fact that Hg deposition is significantly different from sulfate deposition. Sulfate wet deposition shows a clear west-to-east increasing gradient whereas Hg wet deposition shows primarily a north-to-south increasing gradient. These results suggest that sulfate wet deposition is strongly influenced by regional emission sources whereas Hg is not. Instead, Hg wet deposition appears to be influenced primarily by oxidant concentrations that are conducive to the oxidation of Hg^0 to Hg^{+2}.

Comment:

One commenter (OAR-2002-0056-5497) suggested that the Mercury Deposition Network (MDN) data are useful in evaluating the ability of models to reproduce regional patterns of wet deposition of Hg. However, the MDN was never designed to monitor the local deposition of Hg. Consequently, MDN data should not be used to evaluate model predictions of near-field deposition.

For the reasons detailed in EPRI's NODA comments (see OAR-2002-0056-5469), the commenter agrees that the Industrial Source Complex (ISC) and Regional Lagrangian Model of Air Pollution (RELMAP) models used for the Hg Study are not the best means of assessing local and global Hg deposition. These models are outdated and do not reflect the current state of the science. Whatever model(s) EPA ultimately chooses, EPA must recognize that a grid-based model may over predict local Hg deposition by a factor of two or more when compared to the results of a plume model.

Response:

EPA appreciates the commenters input. Please see Chapter 8 of the Regulatory Impact Analysis for a discussion of EPA's air quality modeling analysis. Please also see EPA's Technical Support Document for the Final Clean Air Mercury Rule: Air Quality Modeling.

3. Step 3: Modeling Ecosystem Dynamics. EPA plans to quantify Hg deposition associated with Hg reductions to estimate changes in human exposure to methylmercury that may result from reductions in power plant emissions. This requires quantifying the linkage between different levels of Hg deposition and fish tissue methylmercury concentration. EPA is currently considering using the Water Office's Mercury Maps (Mmaps) for this purpose, supplemented by case studies, and requested comment on this approach. To complement the case studies, EPA asked for both empirical information and modeled scenarios that show the effects of ecosystem properties other than total Hg loading on accumulation in organisms in different ecosystems and, specifically, on new knowledge related to factors affecting methylation and demethylation in a range of aquatic ecosystem types. EPA also sought comment on data and/or analytic tools that can be used to forecast methylation rates and bioaccumulation rates in aquatic ecosystems. EPA received

analyses of the changes in fish concentrations expected as a result of changes in deposition from Chippewa Indians (OAR-2002-0056-2118), Environmental Defense (OAR-2002-0056-2878), Electric Power Research Institute (OAR-2002-0056-2578, -2589, -2593), Hubbard Brook Research Foundation (2038), NESCAUM (OAR-2002-0056-2887, -2890), and TXU Energy (OAR-2002-0056-1831) and asked for comment on their analyses.

Comment:

One commenter (OAR-2002-0056-5544) has been monitoring Hg in sediments and fish in reservoirs on one particular river and its tributaries over the last 30 years. Based on this extensive data set, several observations can be made:

- Mercury levels in this reservoir sediment have declined substantially since 1973.
- Mercury content in fish in the reservoirs was varied but has generally shown constant or reducing trends.
- Generation of power from coal-fired facilities in the region has increased over this period.

The commenter has been working in cooperation with state agencies in the Tennessee Valley to determine the overall condition of streams and lakes and the level of contaminants in fish for three decades. Mutual efforts specifically related to Hg began in 1970 in response to discovery of Hg contaminated fish in the Great Lakes and adoption of guidelines for Hg in fish by the U.S. Food and Drug Administration. The commenter collected a variety of fish species and sediment samples from throughout the are in the early 1970's and reported current fish tissue monitoring program began in 1987 and continued as part of their Vital Signs Monitoring Program. The commenter has monitored hundreds of locations throughout the Tennessee Valley over the years.

Mercury levels in the commenter's area reservoir sediments have declined substantially since 1973. The commenter conducted a special study in 1973 of sediments from the forebay area (i.e., the area just upstream of a dam) of 26 reservoirs. A comparison of the results from 1973 with recent Vital Signs Monitoring data from the same locations indicates a substantial decrease in Hg concentrations throughout the commenter's area from the early 1973s to the late 1990s. The large reduction in sediment Hg occurred in the 1970s as many large industrial users of Hg changed production methods to less Hg-intensive operations. In locations without historical industrial point sources of Hg, no increases have been observed in sediment Hg concentration.

Mercury levels in fish tend to be low in largemouth bass and catfish in the reservoirs of the commenter's main river. In samples collected since 1990's in the reservoirs, largemouth bass show a mean concentration of total Hg around 0.2 mg/kg. Largemouth bass are routinely included in many studies because they are at the top of the food chain. Since 1970, the Hg concentrations in largemouth bass and channel catfish have remained relatively steady with no apparent increase.

In furtherance of its congressional mandate to promote the safe and efficient use of electric energy, the commenter has long supported and conducted research into various subjects associated with the generation of electricity. This includes the publication of various technical reports and studies. Among these publications are a series of "On the Air" reports that are technical notes on important air topics. The November 2004 "On the Air" focused on TVA's sampling of Hg levels in the Tennessee Valley region and was entitled, "Three decades of Mercury Levels in the Tennessee River System". The commenter is enclosing a copy of this document with our comments. It presents the above information in more detail and shows that a decline in Hg concentrations in the Tennessee River has occurred over a period of time when coal combustion has increased substantially (see OAR-2002-0056-5544).

Response:

EPA has examined the commenter's concerns in context of the final rulemaking. As described in the Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls in the docket, we have limited the fish tissue samples to more recent years for some analysis in part for reasons similar to those raised by the commenter.

Comment:

One commenter's (OAR-2002-0056-5559) studies at Little Rock Lake in northern Wisconsin indicated that environmental improvement may be occurring from actions already taken to reduce Hg air emissions. For a five-year period beginning in 1995, researchers measured Hg air deposition, and levels of Hg in lake water and in fish tissue. The studies documented declines in Hg levels for all these parameters with reductions of Hg levels in yellow perch tissue averaging 5 percent annually. The declines measured show that Little Rock Lake is responding more rapidly to changes in deposition of Hg than the decline in acidity from sulfur dioxide emission reductions. This is a promising indication that reducing Hg deposition will lead to lower lake Hg levels as well as a reduction in fish tissue.

Response:

EPA appreciates the commenter's input to the record. We pursued several case studies as described in Chapter 3 of the Regulatory Impact Analysis that address time-lags at various ecosystems.

Comment:

One commenter (OAR-2002-0056-5517) notes that as demonstrated by peer-reviewed research performed by scientists at Princeton University, the level of methymercury in the world's oceans is not controlled by atmospheric Hg. In this respect, a particularly significant omission of the NODA is its failure to note the observation of these Princeton University scientists whose findings provide strong evidence that the concentration of MeHg in the world's oceans does not respond to anthropogenic emissions of Hg. Rather, oceanic biogeochemical processes, possibly involving deep ocean sediments, control the level of methymercury in the

world's oceans. Thus, this commenter believes that regardless of what Hg emissions controls are put in place at coal-fired power plants, the levels of MeHg in ocean fish will remain virtually unchanged.

The commenter points out that EPA, in its NODA, has produced no peer-reviewed data that would contradict the finding of the Princeton study. Moreover, the Princeton study aside, given the fact that the world's oceans contain millions of tons of Hg, reducing some or even all of the less than 50 tons of Hg emissions released from U.S. coal-fired power plants will leave the levels of Hg in the world's oceans virtually unchanged. Consequently, the levels of MeHg in the ocean fish that Americans eat every day will be virtually unchanged. Unless EPA can produce peer-reviewed data that convincingly contradicts the Princeton study findings, it must be presumed as prima facie evidence arguing against any assertion by EPA that curtailing Hg emissions from power plants would have any effect on the level of MeHg found in ocean fish.

If the Princeton study is correct concerning the constancy of the amount of Hg in the world's oceans, then the modeling EPA proposes to use to estimate reductions of MeHg in marine fish is entirely inappropriate and must not be used. This is because the models, by their very design, would incorrectly predict that lowering emissions of Hg from coal-fired power plants will in fact lower the levels of MeHg in the ocean.

However, actual oceanic field data taken by the Princeton University scientists clearly indicate that this is not the case and that regardless of whether atmospheric levels of Hg change, the level of MeHg in the ocean remains unchanged. No model that EPA proposes to use reflects this fact. If these scientists are correct in their surmisal, then limiting emissions of Hg from coal-fired power plants will have absolutely no significant effect on the levels of MeHg in marine fish, consumption of which constitutes the major route of human exposure to this chemical. The commenter states that this important finding has a very significant bearing on estimates of the benefits of reducing power plant emissions of Hg and must be taken into account.

Response:

EPA appreciates the commenter's input to the record. For several reasons described in the Regulatory Impact Analysis, EPA focused its analysis on recreationally caught freshwater fish.

Comment:

One commenter (OAR-2002-0056-5458) did not agree with the EPA formal definition of a Hg hot spot. The definition based on modeling Hg deposition rates by utilities and determining how the removal of those emissions will hypothetically reduce the amount of MeHg in fish is flawed logic. A Hg hot spot is an existing area or region which already has had its natural resources (fish and wildlife) adversely impacted by Hg emissions resulting in the issuance of fish advisories to protect public health. Existing Hg concentrations in fish and wildlife should be used to define Hg hot spots.

The proposed scale of modeling responses of fish tissues to changes in Hg emissions to the atmosphere is unclear in the NODA. National-scale modeling would appear to have a tendency to dilute or obscure the benefits of reduced Hg emissions, particularly for the northeastern and east coast states. This dilution or obscuring of benefits is not scientifically sound or acceptable. For fresh waters of the U.S., modeling should be scaled to at least a regional basis although benefits of Hg emission reductions will be even greater in localities and waters with closer proximity to the sources of Hg emissions.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls in the docket.

Comment:

One commenter (OAR-2002-0056-5502) stated that power plant emission reductions will reduce Hg deposition in the Eastern U.S., and MeHg concentrations in wild freshwater fish are likely to drop in response. Much of the freshwater fish consumed in the U.S. is farm-raised, and does not contribute significantly to exposure. But because so much more marine fish than wild freshwater fish is consumed, the affect on total exposure is modest. The range of exposure reduction from Hg controls under any of the scenarios under consideration was from 0.4-6.5 percent, depending on the state. The average of the calculated state reduction was about 1.6 percent. These reductions apply to those who eat a typical mix of marine and wild freshwater fish, based on state recreational fishing data. Some members of the population such as subsistence fishers may experience greater exposure reductions.

EPA's MMaps tool assumes that 1) there is a linear relationship between atmospheric deposition and MeHg in fish, 2) atmospheric deposition is the only significant source of Hg to lakes, and 3) fish tissue Hg is at steady state equilibrium with the water. Data (from the METAALICUS study) and modeling results negating these assumptions are provided. Furthermore, it is still not possible to accurately forecast either the lag time or the level of response of fish tissue following reductions in Hg deposition. Modeling runs with the commenter's Dynamic Mercury Cycling Model have indicated lag times of decades to more than 100 years. Regardless of the complexity of models describing the behavior of Hg in the environment, characteristics of both terrestrial and aquatic ecosystems such as microbial activity, pH, dissolved organic matter, algal productivity, redox potential, temperature, hydrodynamics, etc. make it very difficult to accurately conduct broad-brush regional modeling of the responses of fish tissues to reductions in atmospheric Hg deposition.

Reductions in Hg emissions from U.S. coal-fired power plants will have only a small effect on U.S. exposures to MeHg. This is because most exposure to MeHg occurs through consumption of marine fish. Marine fish will be largely unaffected by U.S. power plant emission reductions because the reductions are so small, less than 1 percent, of global emissions. The predominance in U.S. commerce of North Pacific marine fish implies an even lower

sensitivity to U.S. Hg reductions, due to prevailing winds and the uncertainty about the availability of MeHg in marine environments.

Response:

The benefits analysis completed for the RIA is not intended to model local-scale changes in fish tissue concentrations and exposures in support of site-specific risk analysis. Instead, modeling conducted for the RIA is intended to capture generalized regional changes in methlmercury exposure resulting from reductions in power plant mercury emissions in order to support a national-scale benefits assessment focusing on the 37-State eastern U.S. study area. For additional details on the benefits analysis modeling framework see Section 10 of the RIA.

EPA recognizes the complexities associated with methylation of mercury deposited in waterbodies and watersheds and subsequent biomagnification within the aquatic foodweb. While there are dynamic fate/transport models that can be used to conduct detailed site-specific modeling of mercury in aquatic and terrestrial environments for purposes of predicting mercury fish tissue concentrations (e.g., the dynamic mercury cycling model), it is not feasible to utilize these resource-intensive models for a regional- or nationals-scale analysis. Therefore, EPA selected the MMAPs models for application in the RIA. EPA fully recognizes the limitations and simplifying assumptions associated with this model, but believes that it has sufficient precision to support a benefits analysis conducted at the regional- or national-scale (i.e., it can capture general trends in mercury fish tissue response to changes in mercury deposition from power plants). However, to provide additional perspective on the relationship between mercury deposition and fish tissue concentration changes (especially in relation to MMAPS linearity assumption and the lag time required for systems to reach steady state), EPA has conducted several detailed local-scale sensitivity analyses. The results of these case studies are presented and discussed in Appendix D.

EPA recognizes both (a) the technical challenges in predicting the change in saltwater fish mercury concentrations resulting from reductions in US power plant emissions and (b) the relatively small contribution that US power plants make to total deposition over saltwater habitats for commercial fish (Note, however that because of the high proportion of US fish consumption associated with saltwater fish, even a relatively low impact of US power plant emissions on those fish could produce significant benefits). Because primarily of technical challenges in translating mercury emissions reductions from US power plants into changes in saltwater fish mercury concentrations, EPA has not included this exposure pathway (saltwater fish consumption) in the primary benefits analysis.

EPA agrees with the commentor that there is significant uncertainty associated with predicting the lag (time) required for fish to reach new steady state mercury concentrations following reductions in mercury deposition to watersheds/waterbodies. EPA also recognizes, that, depending on the specific aquatic system under consideration, lag times could extend over decades. Consequently, EPA has provided benefits results in the RIA reflecting a range of lag periods (from 0 years to 100 years).

Comment:

One commenter (OAR-2002-0056-5465) stated that even working within the narrowly framed revised benefits assessment proposed by EPA, numerous issues arose. The commenter hereby incorporated by reference the arguments elaborated in the attached articles insofar as they spoke to the questions raised by the NODA. In particular, the commenter drew EPA's attention to the discussion and sources cited by Professor O'Neill regarding the biological, chemical, and physical processes relevant to determining Hg exposure for those in the upper Great Lakes.

Response:

EPA appreciates the commenters concerns. EPA addresses ecosystem response to mercury loading in Chapter 3 of the Regulatory Impact Analysis.

Comment:

One commenter (OAR-2002-0056-5535) presented several specific issues that would benefit from such careful peer review. The commenter did not intend this list to be comprehensive, but merely include it to illustrate that the agency must address critical scientific issues prior to making changes to its deposition and watershed models or conducting other components of the proposed analyses. This overview serves to demonstrate that it would be foolish to hold up final Hg regulations while EPA further investigates certain technical issues concerning the emissions, fate, and toxicity of Hg from power plants.

Hg Speciation in Deposition Modeling. The NODA points out that HBRF said that an average speciation profile should not be used when modeling or estimating deposition. This statement was made in the context of Hg deposition modeling because using an average speciation profile for emissions would likely underestimate the amount of local, regional and continental deposition. This is because speciation drives assumptions about the residence time of Hg in the atmosphere, which controls transport and the likelihood that Hg emitted in the U.S. will deposit in outside the U.S. For example, the more Hg emitted as elemental, the higher the proportion of Hg that is transported longer distances. In particular, the EPA should incorporate new speciation data for Northeast plants. A revised speciation profile for Northeast plants is: 70 percent oxidized Hg and 30 percent elemental Hg.

Hg Maps (MMAPS). MMAPS is a useful tool for roughly evaluating the impacts of Hg deposition on fish Hg levels. However, as the agency notes, it is still undergoing external peer review and the commenter expects the agency will need time to address peer review comments. Hindering the applicability of MMAPs is the lack of fish concentration data for many watersheds and the "averaging" of results across large watersheds. The commenter thought MMAPS was best suited to the application for which it was developed–evaluating specific watersheds where additional information on population exposure can be considered when evaluating the results of the assessment.

Response:

EPA appreciates the commenters concerns. Please see EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An

Update, EPA/Office of Research and Development, March 2005) for a discussion of the importance of speciation for mercury capture. Also, please see Chapter 7 of the Regulatory Impact Analysis for a discussion of how we took speciation into account in our power sector modeling and see Chapter 8 for a discussion of how we took speciation into account in our air quality and deposition modeling. See the Regulatory Impact Analysis and the Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls in the docket for a discussion of the application of Mercury Maps assumption.

Comment:

One commenter (OAR-2002-0056-5423) presented a figure illustrating no evidence of increasing trend or any change in Hg of deep-sea fish (blue hake): 1970s versus 1880s fish (Figure E1, see OAR-2002-0056-5423).

> "To test for a change in mercury content in the last century, two samples of the deep-sea fish named blue hake *(Antimora rostrata)* were analyzed. *Antimora rostrata* is resident throughout the world's oceans at depths of 1000-3000 m but does not venture into depths shallower than 800 m [actually about 200 m in the cold waters of the polar region]; therefore, this deep-sea species is not exposed to local estuarine, coastal, or atmospheric inputs of mercury. A sample of 21 specimens collected in the 1880s was compared with a sample of 66 specimens collected in the 1970s in the western North Atlantic Ocean. In both recent and old fish mercury increased as a function of length, but comparison of the two concentration vs. length relationships shows that there has not been an increase in mercury concentration in deep-sea fish in the last century. This result supports the idea that the relatively high concentration of mercury found in marine fish that inhabit the surface and deep waters of the open ocean result from natural processes, not 20th century industrial pollution." [Barber et al. (1984) Environmental Science & Technology, vol. 18, 552-555; Barber et al. (1972) Science, vol. 178, 636-639]

This commenter presented a figure (Figure E1, see OAR-2002-0056-5423) showing that although one can find a clear increase of Hg concentration in the tissue of the deep sea fish (blue hake) caught from western Atlantic waters as the size of the fish increases, one can hardly see any significant changes in the fish tissue Hg-size relation for fish samples caught in 1880s when compared to the modern samples caught in the 1970s. This research clearly suggests that Hg concentration in world ocean fish is not likely to be changed or modified by any amount of alteration of inorganic Hg sources (either anthropogenic or natural). This is why the claim that the current EPA CAMR will lead to a measurable reduction in MeHg accumulated in world ocean fish or even fish from local U.S. lakes is factually misleading. Additional evidence and comments by the commenter follow.

Figure E2 , (see OAR-2002-0056-5423) shows recent results by Kraepiel et. al., (2003,

Environmental Science & Technology, vol. 37, 5551-5558) which found no clear increase in the Hg levels of Yellowfin tuna caught in 1998 relative to a similar cohort caught in 1971.

The theoretical expectation (similar to EPA's) was that the MeHg concentration "should have increased by 9 to 26 percent" over the interval "if methylation occurred in the mixed layer or in the thermocline [of the Pacific oceans]." The theory was *not* proven. The commenter further noted that Zhang et al. (2002, Ambio, vol. 31,482-484) has recently estimated that China's Hg emissions from coal combustion are increasing at the rate of 5 percent per year (from available data from 1978 through 1995), which is consistent with the theoretical expectation of increase in the amount of MeHg in the waters of the Pacific Ocean *if* the Hg-to-MeHg conversion process is sensitive to industrial emissions. To the contrary, Kraepiel et al. (2003) clearly concluded that "[s]uch an increase is statistically inconsistent with the constant Hg concentrations measured in tuna. The commenter concluded tentatively that Hg methylation in the oceans occurs in deep waters or in sediments." (p. 5551). This is why the relatively small man-made sources of Hg emissions can neither overwhelm nor directly alter the natural cycling of Hg in the environment and biosphere.

Independent results shown in Figure E3 (see OAR-2002-0056-5423) support and update the finding of Zhang et al. (2002) that industrial Hg emissions from China (and India) are increasing significantly from 1990 to 2000 and that amount, both in the absolute amount and the rate of increase, dwarfed the rather small amount of industrial Hg emissions from the U.S. EPA's CAMR should seriously consider and weighing this important fact if there is to be any effective Hg emission management rulings.

Figure E4 (see OAR-2002-0056-5423) shows additional new evidence against any increasing trend in Hg levels in fish by examining concentrations in tissue of striped bass from the San Francisco Bay area over the period 1970-2000. The study's findings also clearly show that in any given year there is at least one striped bass sample containing Hg values above EPA's consumption advisory threshold value of 0.5 ppm. Perhaps even more significant, those striped bass with Hg concentration values above 0.5 ppm had no apparent connection to power plant Hg emissions.

Figure E4 (see OAR-2002-0056-5423) illustrates no evidence of increasing trend in Hg concentration in striped bass caught off San Francisco Bay area from 1970-2000. The commenter notes that at any given year there is at least one striped bass with Hg level above the EPA's consumption advisory threshold of 0.5 ppm since 1970 with no apparent tie to any U.S. power plant Hg emission sources. Also although no increasing trend is clear for Hg, declines were noted in the fish tissue's DDT and chlordane in the late 90s. Those declines may be related to the use curtailment of these two chemicals in the 70s and 80s.

Figure E4 (see OAR-2002-0056-5423) reveals another important finding from this new study. Even though no accumulation trend was noted for Hg in striped bass in the 1970-2000 period, significant declines in the late 1990s were noted for other contaminants like DDT and chlordane in San Francisco Bay's fish tissues. The authors suggest that the declines may be

linked to known curtailed usage of the two chemicals in the 1970s and 1980s. Thus, the combined findings suggest a more complicated and complex chain of biomethylation and bioaccumulation for Hg in fish. That is, compared to other contaminants it appears that the pathway and behavior of Hg transformation and accumulation in fish differs significantly.

A similar tendency was recently reported (Yamaguchi et al., 2003, Chemosphere, vol. 50, 265-273) for levels of contaminants in fish from upper River Thames in Britain by a group of zoologists from Oxford University and Cornell University. These authors concluded that although the recent decrease in environmental contamination level of PCBs may be partly associated with industrial and human activities, it was difficult to find such associations for Hg.

Response:

EPA appreciates the commenter's input to the record. For several reasons described in the Regulatory Impact Analysis, EPA focused its analysis on recreationally caught freshwater fish.

Comment:

One commenter (OAR-2002-0056-5423) presented a figure (Figure F1, see OAR-2002-0056-5423) that confirms admission by EPA that trace levels of MeHg in fish depend on the complex physical, chemical, and biological factors within each unique ecosystem. More importantly, it evidences that despite the relatively constant level of total inorganic Hg available in all four (3 open water and 1 salt marshland) of the sampling sites (the four blue bars in Figure F1) in this study, the production and concentration levels of MeHg were significantly enhanced at the biologically active and organically rich marsh wetland site (the tallest red bar marked “marsh” in Figure F1). The authors concluded that “sediment geochemistry (redox, sulfide, pH, organic content, etc.) is a much more important control on MeHg production than is the absolute total mercury concentration” (p. 266 of Marvin-DiPasquale et. al., 2003, Environmental Geology, vol. 43, 260-267).

The San Francisco Bay findings add to the body of evidence showing that either adding or reducing Hg atmospheric deposition from any coal-fired power plant would not measurably affect MeHg levels in the San Francisco Bay ecosystems. To the contrary, MeHg levels are naturally self-limited by specific ecosystem dynamics, water quality variables like dissolved sulfate, parameters like the population of algae and/ or zooplankton, availability of nutrients and/or sunlight and so on.

Response:

EPA appreciates the commenter's input to the record. For several reasons described in the Regulatory Impact Analysis, EPA focused its analysis on recreationally caught freshwater fish.

Comment:

Generally agreeing with EPA's assessment, one commenter (OAR-2002-0056-5423) offers an additional new and important model validation target for EPA's modeling team to factor. Figure G1 (see OAR-2002-0056-5423) shows a very important observation concerning the accumulation of MeHg in various watershed systems. It shows a particular "MeHg accumulation paradox" in that the relative percentage of MeHg converted from raw Hg available actually *decreases* as the amount of raw Hg available *increases.* The authors of these important findings suggest that as the amount of raw Hg increases in a watershed system, there are actually more bacterial operons (i.e., bacterial enzymes encoded by the Hg resistance *(mer)* operon) available to significantly break down the MeHg produced, and thus explaining the observed "MeHg accumulation paradox." Again, the proposed EPA's CAMR needs to fully account for the underlying science before making costly and ineffectual compliance rulings.

Response:

EPA appreciates the commenter's input to the record. EPA's ecosystem modeling is described in detail in Chapter 3 of the Regulatory Impact Anaysis.

Comment:

One commenter (OAR-2002-0056-5423) believed it is very important to emphasize that the best available science suggests repeatedly that the stated assumptions in EPA's MMaps model are likely to be wrong. Therefore, they cannot be meaningfully applied for a realistic assessment of how a change in Hg emissions from power plants can possibly affect concentrations of MeHg in fish.

First, Figure D1 (see OAR-2002-0056-5423) provides real data that "the physical, chemical, and biological characteristics of the ecosystem(s)" never remained constant over time. That alone invalidates the critical model assumption.

Figure H1 (see OAR-2002-0056-5423) offers another important target for validating the assumptions in EPA's MMaps model. It shows that local atmospheric deposition of Hg has negligible contribution to the annual budget of Hg to the Lake Whatcom ecosystems, thus directly challenging EPA's MMaps assumption that "air deposition is the only significant source of Hg to a water body."

No local man-made Hg "pollution" at Lake Whatcom, Bellingham, WA: Annual input of Hg from local industrial sources is negligible

Paulson (2004) Sources of mercury in sediments, water, and fish of the Lakes of Whatcom County, Washington, U.S. Geological Survey Scientific Investigations Report 2004-5084 (August 2004)

The author of the new Lake Whatcom study further noted:

"Concerns about mercury (Hg) contamination in Lake Whatcom, Washington, were raised in the late 1990s after a watershed protection survey reported elevated concentrations of Hg in smallmouth bass. The USGS ... cooperated to develop a study to review existing data and to collect new data that would lead to a better understanding of Hg deposition to Lake Whatcom and other lakes in Whatcom County. Of all the lakes examined, basin 1 of Lake Whatcom would have been most affected by the Hg emissions from the chlor-alkali plant and the municipal sewage-sludge incinerator in the City of Bellingham. The length-adjusted concentrations of Hg in largemouth and smallmouth bass were not related to estimated deposition rates of Hg to the lakes from local atmospheric sources. Hg concentrations in dated sediment core samples indicate that increase in Hg sedimentation were largest during the first half of the 20th century. Increases in Hg sedimentation were smaller after the chlor-alkali plant and the incinerators began operating between 1964 and 1984. Analysis of sediments recently deposited in basin 1 of Lake Whatcom, Lake Terrell, and Lake Samish indicates a decrease in Hg sedimentation." (p. 1 of Paulson, *Sources of mercury in sediments, water, and fish of the Lakes of Whatcom County, Washington*, U.S. Geological Survey Scientific Investigations Report 2004-5084, August 2004)

Response:

EPA appreciates the commenter's input to the record. EPA's ecosystem modeling is descbribed in detail in Chapter 3 of the Regulatory Impact Analysis. Also see the Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls in the docket.

Comment:

One commenter (OAR-2002-0056-5423) believed that it should be fairly clear from the peer-reviewed literature exhibited in comments (A) through (H) that EPA's MMaps isn't simply suffering from "limitations," but is instead terminally overwhelmed by numerous demonstrably flawed assumptions in its irrational determination to claim a reduction of Hg emissions from U.S. power plants can or will lead to a reduction in accumulation of MeHg in ocean or U.S. freshwater fish.

Figure I1 (see OAR-2002-0056-5423) presents for EPA's modelers yet additional, recently published fish Hg data sets of various sport fish species caught from 17 "areas of concern for Hg contamination" in the Canadian Great Lakes from 1971 to 1997. The results again evidence that historical changes in Hg concentrations are not simply to be expected from local industrial Hg emissions. In fact, the author concluded that, "Differences observed [among different areas of concern] did not consistently parallel expectations associated with historical

presence of chlor-alkali plants in the vicinities of some locations." More importantly, the author also noted that "An attempt to correlate the fish tissue Hg with the frequency of occurrence of infantile cerebral palsy at AOC [areas of concern] was unsuccessful." Further Hg-related health issues are addressed in comments (K) through (Q) in e-docket text.

"The tissue mercury concentration in six species of fish collected at the 17 Areas of Concern [AOC] were analyzed. A linear increase in Hg concentration with fish length was found, but slopes differed among locations. The temporal pattern over the period 1971-1997 differed across species in fish collected in Lake St. Clair; in at least two species there was evidence of increased Hg concentration during the 1990s that had been suggested in an earlier analysis. AOC differed significantly in observed tissue concentrations. Differences observed did not consistently parallel expectations associated with historical presence of chlor-alkali plants in the vicinities of some locations. An attempt to correlate the fish tissue Hg with the frequency of occurrence of infantile cerebral palsy at AOC was unsuccessful."

Response:

EPA appreciates the commenter's input to the record. The limitations and aplication of Mercury Maps is described in detail in the RIA and Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls in the docket.

Comment:

One commenter (OAR-2002-0056-5423) notes that this partial admission on the highly limited use of MMaps by EPA goes a long way toward illustrating the commenter's concerns regarding the scientifically questionable direction of EPA's modeling effort. Figure J1 (see OAR-2002-0056-5423) confirms that the top 15 fish and sea foods consumed in the U.S., representing about 90 percent of the U.S. commercial market, is accounted for by marine and farm-raised species. (According to UN statistics, domestic fresh water fish may account for as little as 0.05 percent of total U.S. consumption.) This alone renders EPA's MMaps modeling results on MeHg levels in freshwater fish almost irrelevant or largely insignificant.

Considering the insignificant Hg emissions from U.S. coal-fired power plants (i.e., less than 1 percent of annual global emissions budget) and the millions of tons of natural Hg available in world oceans from deep venting, it is clear that there will be no detectable change in trace MeHg in oceanic fish even if EPA were to impose zero emission standards for all U.S. Hg sources. Evidence provided in comment (E) (i.e., Figures El, E2 and E4, see OAR-2002-0056-5423) alone should be adequate for our hypothesis. (If trace levels of MeHg did not increase in a wide variety of fish along with rapidly growing worldwide anthropogenic emissions (See figure E3), what rationale is there that fish MeHg levels would drop in response to falling U.S. emissions?) Meanwhile, the strictest burden of proof for EPA rule making demands a clear demonstration (not invalid modeling assumptions) that its CAMR rulings can deliver a clear and meaningful reduction in MeHg in world ocean fish. Seafood Consumed in

the U.S. Accounts for 90 percent of the Commercial Market. Source: Carrington and Bolger (2002) Risk Analysis, vol. 22,689-699 + updates in Carrington and Bolger (2003) ‘s Intervention Analysis Draft Report.

Response:

EPA appreciates the commenter's input to the record. The limitations and aplication of Mercury Maps is described in detail in the RIA and Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls in the docket.

Comment:

Using a global model such as the GEOS-CHEM model to provide the boundary conditions for a continental model (REM SAD or CMAQ) is a more scientifically sound approach than prescribing those regional boundary conditions. It is necessary to conduct a performance evaluation of the global model to ensure that the boundary conditions provided to the continental model are realistic. It is also desirable to have a consistent formulation of the physical and chemical processes governing the Hg species concentrations in both the global and continental models.

Response:

EPA appreciates the commenter's input to the record. For discussion of the air quality modeling, please see chapter 8 of the RIA and EPA’s Technical Support Document for the Final Clean Air Mercury Rule: Air Quality Modeling.

Comment:

One commenter (OAR-2002-0056-5535) presented several specific issues that would benefit from such careful peer review. They did not intend this list to be comprehensive, but merely included it to illustrate that the agency must address critical scientific issues prior to making changes to its deposition and watershed models or conducting other components of the proposed analyses. This overview serves to demonstrate that it would be foolish to hold up final Hg regulations while EPA further investigates certain technical issues concerning the emissions, fate, and toxicity of Hg from power plants.

Atmospheric Hg reactions. Another problem with EPRI’s global Hg model is the incorporation of atmospheric Hg reactions that are very uncertain. In particular, the incorporation and effect of Hg reduction reactions needs investigation. It is also unclear whether the EPRI or EPA models fully account for the many conversion processes that can occur in the atmosphere or the conversion/uptake of Hg by the forest canopy. Both of these processes would increase local deposition. Specifically, it is now well-documented that elemental Hg is converted to oxidized Hg in the presence of ozone and chloride. This is particularly important

along the eastern seaboard where both ozone and sea salt are high.

Community Multiscale Air Quality (CMAQ) model. The commenter understood that EPA has been developing CMAQ over a number of years as a potential replacement for REMSAD. However, the commenter stated that the CMAQ is not yet in the public domain and has not been externally peer-reviewed to the extent it must be prior to its adoption by EPA.

Response:

EPA appreciates the commenter's input to the record. For discussion of the air quality modeling, please see chapter 8 of the RIA and EPA's Technical Support Document for the Final Clean Air Mercury Rule: Air Quality Modeling.

Comment:

One commenter (OAR-2002-0056-5423) agrees with EPA's call for increased understanding about how dry Hg deposition adds to the total ecosystem deposition. Figure D1 shows a new set of Hg deposition data obtained from sedimentary cores representative of the past 11,000 years in Elk Lake in Minnesota. These data might serve as an important benchmark in wet and dry depositions under a very wide range of meteorological and climatic conditions as well as a variety of Hg sources (for example, Hg-enriched dusts and sands from nearby Nebraska sand hills or Hg from local and regional forest fires) for EPA's REMSAD and CMAQ models to demonstrate both the correctness and robustness of their atmospheric transport, chemistry and deposition modules. Measurements of Hg over the past 11,000 years in Elk Lake, MN show that today's Hg level *is neither exceptional nor alarming.*

Response:

EPA appreciates the commenter's input to the record. For discussion of the air quality modeling, please see chapter 8 of the RIA and EPA's Technical Support Document for the Final Clean Air Mercury Rule: Air Quality Modeling. Please see Chapter 3 of the CAMR Regulatory Impact Analysis for a detailed discussion of mercury in the environment, including an assessment of the response time for systems after a change in mercury deposition.

Comment:

One commenter (OAR-2002-0056-5497) noted that EPA was the major co-funder of a technical workshop on Mercury Monitoring and Assessment held in Pensacola, Florida, on September 14-17,2003. The Workshop was also co-funded by EPRI and sponsored by the Society of Environmental Toxicology and Chemistry (SETAC). Participants included 32 Hg scientists from academia, industry, government, and nonprofit organizations. The purpose of the workshop was to identify a variety of environmental and ecological indicators to assess trends due to changes in Hg emissions and fluxes to the environment. Participants at the workshop were also charged with the preliminary development of a network of monitoring stations with

emphasis on North America in order to evaluate the effects of Hg regulatory actions being implemented by Canada and the U.S.

Two products from this workshop will be published in 2005. A paper, Monitoring the Environmental Response to Changing Atmospheric Mercury Deposition (Mason et. al., in press), is scheduled for publication in Environmental Science and Technology in its January issue. In addition, a book, Mercury Monitoring and Assessment (Newman et. al., in preparation), will be published by SET AC Publications later this year. This major, EPA-initiated effort is not mentioned in EPA's proposed revised benefits assessment. Since the direct monitoring of Hg impacts on human, wildlife, and ecosystem health would provide the most irrefutable evidence of the success (or lack of success) of EPA's regulatory strategy, this initiative should be given a primary role in EPA's benefits assessment.

The Relationship of Reductions in Air Deposition of Mercury to Methylmercury in Fish Tissue

EPA's benefits analysis requires that it quantify how a reduction in Hg emissions to the air translates into reductions of MeHg in fish tissue. The most important thing for EPA to recognize is that a reduction in air emissions of Hg cannot be expected to result in a reduction in fish tissue Hg in a manner that is predictable by a generally applicable rule–whether linear, sub-linear, or time-dependent. The entire array of physical, chemical, and biological processes that influence the conversion of elemental Hg in the air to MeHg in fish tissue is complex. Moreover, the relative importance of these factors differs on a site-specific basis.

EPA proposes to use a steady state source-receptor model (Mercury Maps or MMaps) as a tool to predict the biological responses (changes in Hg content) to reductions in emissions of Hg from coal-fired utility boilers. As explained in more detail below, Mercury Maps should only be used as a preliminary screening tool whose results must be ground-truthed by subsequent, more definitive investigations.

Additionally, any screening tool must recognize that only Hg deposited directly to a water body (or flowing overland without reacting with soil) is readily and quickly incorporated into biota. Mercury deposition to uplands does not readily migrate to waterbodies but instead becomes incorporated into the humic matter of soil. While some very small amount of this Hg in soil may eventually leach to a water body, such a process occurs over decades, so that any newly deposited Hg has an insignificant effect on the total amount of Hg that has already accumulated in soil over thousands of years. Any modeling process that EPA uses must treat deposition directly to the lake surface differently from deposition to the surrounding uplands.

The Florida Mercury Report Does Not Demonstrate that Changes in Air Emissions Result in Rapid Changes in Fish Tissue Mercury

EPA should not give undue weight to a study in Florida that shows large reductions in

fish tissue Hg in the aftermath of reductions in air emissions. For one thing, the Everglades, where this study was conducted, are a unique ecosystem, and results from the Everglades cannot be extrapolated to other locales.

In November 2003, the Florida Department of Environmental Protection combined two earlier Hg reports into a single document that the commenter will call the "Florida Study". This report has been widely publicized and widely misinterpreted. It does *not* show that reductions in air deposition will rapidly be followed by reductions in fish tissue Hg, and certainly not outside the unique environment of the Everglades.

Analyses of the Florida Study by EPRI reveal the following important facts:

- The Hg emissions released by municipal and medical waste incinerators are different from those released by power plants.
    - There are two major forms of Hg in emissions–oxidized (ionic), which is water soluble, and elemental, which is not water soluble.
    - Most incinerator Hg is in the water-soluble form, whereas the form of Hg released from power plants depends upon many factors such as the type of coal being burned. Recent research has shown that most of the Hg released by utilities (at least 60 percent) is the non-water-soluble elemental form and that a significant amount of the remainder converts to this non-soluble form shortly after leaving the stack.
    - The form of Hg emitted is critical, because oxidized Hg can be washed into local rivers, lakes, and streams by rainfall, whereas elemental Hg is carried away by wind and enters the global Hg cycle.
- The Florida Everglades Study represents a unique ecological system not typical of, and in fact strikingly different from, other US waterways. Thus, the results from this study are not necessarily applicable to other areas.
    - The Everglades are in a tropical zone (no seasons), the water is shallow, and the bottom sediments are much different from those in other water bodies throughout, the U.S. Other waterways also have different levels of acidity, biological activity" dissolved oxygen, and turbidity. These differences can dramatically affect Hg cycling and uptake by biological organisms. Thus, it is unlikely that the changes in Hg in fish, both the amount and the rate of decline, would be observed in other U.S. waters.
- The claim that changes in Hg emissions result in rapid changes in fish Hg content is not supported by the data or findings.

- The Florida Study assumes that Hg deposition in the Everglades originates only from local sources (primarily incinerators and power plants). However, data measurements and long-range transport modeling indicate otherwise.

- In fact, despite decreases in Hg emissions from incinerators, no deposition data exist spanning the reduction period, and other regional and global changes were occurring during the same period. Therefore, it is not possible to determine how much, if any, the amount of Hg being deposited in the Everglades has changed.

- Indeed, both EPA and EPRI have modeled Hg transport and concluded that over 60 percent of Hg currently deposited in Florida originates outside the U.S. Guentzel *et al.* (200 I) hypothesized that long-range (global) transport of reactive gaseous Hg (RGM), coupled with strong thunderstorm activity during summer months, represents > 50 percent of the Hg deposition in southern Florida.[58] The authors highlight the importance of non-atmospheric loading factors and global sources of Hg:

- The contrast between uniform Hg deposition and geographical "hot spots" in fish Hg concentrations from the Everglades region further suggests that aquatic/terrestrial Hg cycling processes, rather than atmospheric source strength, are responsible for the hot spots... .From our analysis of the data, we conclude that significant reduction in rainfall Hg deposition over the Florida Everglades will likely require reductions in local and global Hg emissions.

    - In addition, not all the change in fish Hg content can be attributed to the unknown change in deposition because other factors that mediate the ecosystem response to Hg load have also changed. Several theories have been suggested involving changing nutrient levels and water flows in the Everglades. Further research is needed to understand this situation.

- The atmospheric transport model used by the State of Florida to estimate Hg deposition has limitations.

    - The model does not incorporate chemical reactions in the atmosphere. It also does not include global sources of Hg, only local emissions. Thus, it cannot effectively simulate the actual Hg deposition.

- EPRI's recent research findings indicate that power plant Hg controls would not significantly change the amount of Hg contained in fish, or the human exposure to it.

    - In early 2003, EPRI completed a comprehensive study of U.S. power plant Hg emissions, potential Hg controls, and responses of fish to changes in Hg in their habitat waters. The results showed that reducing Hg emissions from power plants by approximately 50 percent would result in a reduction of Hg in fish of about

1½ percent. This study, combining atmospheric data and models, fish consumption information from U.S. government studies, and an economic model of the U.S. utility industry, relies on more recent information than the two-year-old Florida study report released on November 6, 2003.

The Steady-State Linear Relationship Between Air Deposition and Methylmercury Concentrations in Fish as Reflected in the Mercury Maps Model Is Not Generally Appropriate

EPA requests comment on the use of the steady-state linear relationship between air deposition and MeHg concentrations in fish, as reflected in the MMaps model. The MMaps model was developed by EPA's Office of Water to assess what levels of reduction in Hg deposition would be needed to achieve the fish Hg criterion of 0.3 ppm. It was intended to apply only to watersheds where the principle source of Hg is atmospheric deposition and where there is no known land-based source of Hg discharge into the waterways.

The MMaps model is simplified compared to other models and for that reason can be applied over a broader geographic scale. But it has limitations, among which are the following:

- The model uses the arithmetic average of all fish Hg data in each Hydrologic Unit Code (HUC) watershed. This averaging may blur the substantial differences in water chemistry and fish Hg, both spatially and temporally, that are known to exist within a single watershed. An alternative approach may be to associate the fish Hg level with both the deposition loads as well as other relevant water chemistry parameters (pH; nutrient levels; extent of anoxia in waterbody; water temperature; etc.). This may provide a better prediction of the responses in specific waterbodies as opposed to making a prediction of the fish Hg response for an entire HUC watershed. Further, the analysis should be confined to a particular species of fish, preferably with a similar size or weight range.

- The output of MMaps is highly dependent on the extent of state-specific fish tissue data records. For states that have a relatively long record offish Hg levels from a variety of water body types, the accuracy of the true existing Hg levels is relatively high. For states that have monitored Hg levels in fish only recently, or sporadically, the comparison of "average" HUC fish tissue Hg to EPA's MeHg fish tissue criterion incorporates high uncertainty. EPA's summary of state fish tissue monitoring data for 1990-95 indicates considerable state-to-state variation in the number of water bodies sampled, the number of total collections, the species sampled for, the number of fish analyzed, and the frequency of monitoring. The report also indicates the distribution of species sampled for Hg levels. Two sport fish species (largemouth bass and channel catfish) were sampled more extensively than any other species. Only two states (Kansas and Washington State) do not report Hg levels for largemouth bass. EPA should consider standardizing MMaps by using Hg analysis data for two species only: largemouth bass and channel catfish. A standardization of fish length or age would further increase the accuracy of what

watersheds actually may have fish that exceed the human health fish tissue criterion.

- The EPA report uses the modeling results from the Everglades TMDL to help corroborate the assumption of a linear response. However, there are two concerns, as noted above. First, the Everglades TMDL assumed all the fish changes were caused by local emission changes and did not consider other regional and global changes or any local ecosystem changes that would mediate that assumption. Thus, the actual reduction in fish Hg due to atmospheric deposition reduction in the U.S. would be less than predicted by Mmaps if the simulated changes in Hg deposition from changes in U.S. emissions do not account for global sources. Second, the intercept was considered by the TMDL researchers to be due to the fact that sediment Hg is recycled to the water column by macrophyte roots. The redistribution of Hg from sediments may be an important source to the water column in some waterbodies. Matty and Long found that, in the Great Lakes, the most important processes influencing levels of Hg in sediments (decay of organic matter, iron and manganese redox cycling, exchange of Hg from porewater to sediments) would result in the long-term retention of Hg near the sediment-water interface. This Hg would be available for assimilation by benthic organisms. This source (legacy sediment Hg) would not be influenced by cutbacks in atmospheric deposition. The TMDL report also stated that the intercept is partly a function of the length of simulation time–the longer the time, the smaller the intercept.

- The assumptions that are critical in causing the model to exhibit a linear response to air deposition were discussed in the Everglades TMDL report but were not discussed in the EPA report. These assumptions include:

    - Methylation was allowed to occur only in sediment, based on porewater Hg(II) concentration. Large stratified reservoirs and lakes with anoxic zones can have methylation in the water column. Thus, the Everglades system is not representative of all types of waterbodies.

    - Geochemical factors that could influence the Hg(II) concentration in the porewater such as cinnabar formation were not included. If such factors are controlling the Hg(II) concentration, then a reduction in deposition load may not cause a linear change in Hg(II) concentration.

    - Methylation/demethylation rates were limited only by Hg substrates. Other factors such as carbon supply are important and can influence the rates. Watras et. al., studied 15 lakes in northern Wisconsin, and found relatively low concentrations of sediment MeHg. The authors suggested that a high rate of demethylation accounted for this observation. Based on recent work by Marvin DiPasquale et. al. (2000), demethylation rates become nonlinear at high concentrations of Hg. This latter possibility was not considered in the Everglades TMDL, although it may be less important in that system than in waterbodies with natural elevated Hg.

- The model is based on a uniform linkage between atmospheric deposition of Hg and the amount that reaches a waterbody for eventual uptake by fish. This type of analysis does not consider the effect of varying retention based on different types of land uses and the effect of canopy type on dry deposition. The actual response to the same decrease in atmospheric load would vary across watersheds because the proportion of the load reaching the waterbody would not be the same.

- The apparent linear response of fish to decreases in atmospheric loading does not seem compatible with a hypothesis of differing methylation efficiency in waterbodies. Other factors such as temperature are important in controlling fish metabolism, which then influences the response of fish to a given MeHg concentration. A more detailed comparison of fish data with wide geographic coverage to the Hg deposition data may reveal that the response is not as linear as thought.

- Variability in the fish data could be used to derive an estimate of the uncertainty in fish response to any l ad .cutbacks. The assessment of variability in an explicit form. allows policy makers to determine whether small changes in fish tissue Hg as a result of changing deposition loads will be masked by the inherent variability of the data and so may be unmeasurable or even indiscernible. Due to multiple factors such as fish species, age, size, and changes in diet during their lifetime, fish data for a given waterbody are extremely variable.

- The fish data set could be extended to include other available data, particularly to close the data gap in several of the western states, where no geo-referenced fish data were presented in Mercury Maps.

- EPA acknowledges the need for higher resolution modeling in order for predictions of fish Hg changes to have some accuracy:

- Estimates of percent air deposition reductions, by watershed, as generated from a regional air deposition model, would be needed to predict fish concentration changes.

In summary, the commenter believed that the scientific knowledge of Hg source and receptor processes should compel EPA to use MMaps as a preliminary screening tool only, subject to verification by watershed-specific information. All in all, the key assumptions of MMaps (all Hg from atmospheric sources and equilibrium conditions for Hg levels in fish and other compartments) make the predictive analysis highly sensitive to variable watershed processes, physical and chemical factors affecting methylation, and biological interactions. All of these factors are known to control, or influence, Hg cycling and bioavailability.

An Evaluation of the EPA's Assumed Linear Relationship Between Changes in Atmospheric Emissions and Resulting Fish Tissue Mercury Concentrations-The Great Lakes

The commenter stated that there is a considerable amount of information on Hg sources to the Great Lakes, as well as Hg deposition, rates of sediment accumulation, and measured levels in Great Lakes fish. Using this information, one can evaluate the key assumptions of the linear source-receptor response by comparing the long-term (and new) information on the Hg in the Great Lakes, against the predictions inherent in the linear model.

1. Sources of Hg and deposition to the Great Lakes

Cohen et. al., modeled the total annual deposition of Hg to the Great Lakes, and the relative contributions by specific sources (industry sector, U.S. vs. Canadian sources). They estimated that the annual atmospheric deposition of Hg to Lake Michigan was highest (750 kg/yr), followed by Lakes Superior, Erie, and Huron (425-490 kg/yr), and Lake Ontario (220 kg/yr); however, current and historic additions of Hg are much greater than atmospheric deposition in the case of Lake Superior. In an earlier publication, Shannon and Voldner reported estimates of annual deposition to the Great Lakes. Lake Erie and Lake Michigan had the highest estimated deposition (728 1,012 kg/yr), followed by Lake Superior. Lake Ontario had the lowest estimated annual deposition (297 kg/yr). Interestingly, the authors also found that the estimated annual rate of Hg volatilization from all lakes (2.3-13.7 t/yr) was within the range of total Hg loading to all lakes (4.7 t/yr).

2. Sediment Hg levels in the Great Lakes

In a recent publication, Marvin et. al., reported on long-term sediment Hg levels in the Great Lakes. Based on the most recent surveys, Lake Huron had the lowest sediment Hg levels. The western basin of Lake Erie had the second highest sediment Hg levels, while Lake Ontario had the highest levels. These Hg level patterns would not be expected based on total atmospheric load (deposition) estimates. If annual deposition of Hg alone dictated sediment Hg, the highest Hg levels would be expected in Lake Michigan, while the lowest sediment Hg levels would be expected in Lake Ontario. The authors, however, clearly pointed out the differences in Hg sources to each of the Great Lakes. While estimates indicate Lake Superior receives most of the external Hg loading from atmospheric sources, the relatively high sediment Hg levels in Lake Ontario are due to localized (major urban) sources, and Hg loads coming from the Niagra River. Clearly, for the Great Lakes, Hg deposition information alone cannot be used to predict resulting comparative sediment levels. The authors indicate that sediment Hg levels have declined drastically across the Great Lakes since the 1960s: lakewide decreases in mean sediment levels ranged from 25 percent (Lake Ontario) to 80 percent (Lake Huron).

3. Mercury levels in Great Lakes fish

If EPA's linear source-receptor response assumption were valid, then one would expect that Hg levels in Great Lakes fish would mirror comparative deposition rates, when compared across identical species and age classes. The Canadian Department of Fisheries and Oceans summarized information on long-term Hg level trends for two species sampled in all of the Great Lakes: rainbow smelt and lake trout. Mean concentrations for the years 1977-1995 were

presented. The lowest Hg levels are found in lake trout from Lake Erie–(average concentration during 1990-1995 (0.6 ppm); lake trout from Lake Ontario had the second lowest mean concentration (0.8-0.9 ppm), and lake trout from Lakes Superior and Huron had the highest mean Hg levels (1.2-1.3 ppm). For smelt, once again Lake Erie samples contained the least amount of Hg (0.2 ppm), Lake Ontario samples had the second highest level (0.21-0.25 ppm), and Lakes Huron and Superior fish samples had the highest Hg levels (0.4 and 0.55 ppm, respectively). Long-term Hg concentration data for two sentinel fish species in the Great Lakes indicate, like sediment data, that atmospheric deposition information alone provides no useful information for resulting levels of Hg in lake biotic and abiotic compartments.

Factors Affecting Methylation

The factors affecting methylation of Hg were summarized in a 2003 report entitled "Implementation of EPA's Methylmercury Criterion for Fish Tissue," by AMEC Earth and Environmental and ENVIRON with support from the EPRI.

Formation of MeHg in aquatic systems is influenced by a number of environmental factors. While the microbial activity and the concentration of bioavailable Hg primarily determine methylation rates, parameters such as temperature, pH, redox potential, and the presence of inorganic and organic complexing agents playa complex, yet poorly understood, role in the methylation process. The following is a list of some technical publications that indicate the most important factors controlling Hg mobility and bioavailability:

Microbial Activity: It generally is believed that anaerobic sulfate-reducing bacteria are the principal methylators of inorganic Hg in both freshwater and estuarine environments (e.g., Gilmour et. al., 1992). Recent studies also indicate that these same bacteria also are capable of mediating MeHg degradation. Not all sulfate-reducing bacteria are capable of Hg methylation, and methylation rates are not always correlated with sulfate concentration or with sulfate-reduction rates. The efficiency of microbial MeHg production appears to depend chiefly on the activity and structure of the bacterial community, bioavailable Hg concentration, and the availability of nutrients and electron acceptors such as sulfate (Choi and Bartha 1994). According to Compeau and Bartha (1985), the methylation potential of sulfate-reducing bacteria is greatest in sulfate-limiting environments, but at high sulfate concentrations, sulfide produced in respiration may inhibit methylation through the formation of HgS precipitates or charged Hg-S complexes that are not readily bioavailable.

Sulfide: Several studies have reported that high sulfide concentrations inhibit MeHg formation, and an inverse relationship between sulfide concentration and MeHg production in sediments and pore waters also has been observed. On the other hand, increased MeHg production also has been observed under certain sulfide concentrations (e.g., Craig and Moreton 1983). This suggests that, while high concentrations of sulfide can greatly reduce MeHg production, methylation is not usually completely inhibited (Ullrich et. at., 2001). It is generally believed that the inhibitory effect of sulfide on methylation is due to the formation of insoluble HgS precipitates that are not bioavailable. However, high concentrations of dissolved Hg

observed in sulfidic porewaters suggests that sulfide may actually help mobilize Hg through the formation of soluble Hg-sulfide complexes. Sulfide may also affect methylation through the formation of neutral HgS^0 species that can diffuse readily through cell membranes (Benoit et. al., 1999). On the other hand, formation of charged polysulfide complexes actually can decrease bioavailability, but its effect on methylation is not clear. As the primary pathway for methylation is by sulfate-reducing bacteria, more research is needed to identify the role of various sulfur species and other parameters on MeHg formation.

Temperature: Several studies have indicated that maximum methylation activity occurs during mid- or late summer (e.g., Watras et. al., 1995). Other studies have found higher MeHg concentrations in spring than in summer. While increased temperature can contribute to increased microbial activity, it also affects seasonal changes in productivity/nutrient supply, redox conditions, and demethylation rates.

pH: There has been concern that low pH values may lead to increases in the production and/or bioaccumulation of MeHg because elevated Hg levels have been observed from fish in acidified lakes. Enhanced methylation has been observed in low-pH waters and sediments; however, this process is dependent on the redox state of the system (in anaerobic systems, acidic pH lowers MeHg production) and other factors. pH may indirectly affect methylation by altering the mobility and partitioning of Hg and MeHg in soils, stimulating MeHg production through the addition of sulfate (in acid rain) and by changing microbial activity (particularly the 49 sulfate-reducing species) or cellular uptake of Hg^{+2}. Changes in pH also can alter Hg speciation (e.g., enhanced production of elemental Hg, altering the binding of Hg to organic matter and other ligands), which in turn can affect the amount of ionic Hg available for microbial methylation. Demethylation rates are also pH-sensitive, albeit to a lesser extent than methylation rates.

Organic Matter: The role of organic matter in methylation also is very complex and poorly understood. Observed increases in MeHg concentrations with higher dissolved organic carbon (DOC) concentrations have been attributed to a stimulating effect of organic nutrients on microbial methylation activity (i.e., microbes utilizing organic matter as energy source when sulfate is limiting). Direct abiotic methylation of Hg by humic and fulvic acids (the refractory portions of dissolved organic matter) also could be very important, particularly in wetlands where high generation of MeHg has been observed. This mechanism largely has been ignored and, to date, it is not clear to what extent abiotic methylation contributes to MeHg production in organic-rich sediments and lake waters. It may be hypothesized that where organic matter is labile and readily biodegradable, it may promote methylation by stimulating microbial growth, and where the organic matter is recalcitrant and consists of high-molecular-weight humic and fulvic acids, it may contribute to abiotic methylation.

Decreased methylation has also been observed at high concentrations of organic matter in both natural systems and experimental studies, and it has been suggested that DOC may strongly bind with inorganic Hg at sulfur-containing functional groups, rendering them unavailable for bacterial methylation. Even if MeHg forms, it may be complexed by DOC and, therefore, not available for bioaccumulation. DOC also can compete with sulfide for Hg binding and favor the

mobilization of Hg through the formation of Hg-DOC complexes. In Hg binding with DOC, pH may play an important role where protons compete with metal binding sites in organic matter. Humic substances, which are recalcitrant, high-molecular-weight fractions of organic matter, also can reduce Hg^{+2} to the volatile Hg^0 species, both directly as well as by enhancing the reduction rates in photochemical reactions, thus reducing the Hg burden available for methylation.

Redox Conditions: Even though Hg methylation occurs in both aerobic and anaerobic conditions in the natural environment, methylation rates are highest in anoxic sediments and waters, and the stability of MeHg is greatest in anaerobic environments. This may be due to the reduced activity of sulfate-reducing bacteria under aerobic conditions and the enhanced degradation of MeHg in aerobic conditions. It appears that anaerobic methylation is predominantly microbial in nature and, therefore, enhanced by the presence of organic matter; whereas abiotic methylation is favored under aerobic conditions and is suppressed by the presence of organic matter (possibly due to complexation with organic matter rendering Hg unavailable for methylation). Methylmercury concentrations usually are highest in the moderately anaerobic surface sediments (mostly at the oxic-anoxic interface) and rapidly decline with depth. Likewise, in stratified lakes and estuaries, MeHg concentrations are usually highest at the oxic/anoxic boundary layer. Changes in redox conditions in water column and sediment layers also result in seasonal variations in MeHg concentrations. Organic matter, nutrients, pH, and sulfides significantly influence the redox effects on MeHg production.

Salinity: The methylating activity in marine and estuarine sediments is usually lower than in freshwater sediments, partly due to salinity effects. The negative effect appears to be a result of formation of charged sulfide complexes (from sulfate in sea salt) in seawater and charged Hg-chloride complexes such as $HgCl_4^{-2}$ that limit the methylation process. Thus, estuarine fish tend to have lower MeHg in their tissue than comparable species in freshwater fish (Gilmour and Riedel 2000).

In summary, Hg methylation is primarily a microbially mediated process, and the precise mechanism of MeHg formation still is unclear. Mercury methylation and demethylation rates in aquatic systems are influenced by both the speciation and biochemical availability of Hg and by a large number of interrelated environmental variables, such as biological activity, nutrient availability, pH, temperature, redox potential, and inorganic and organic complexing agents. The importance of each of these parameters and their complex interactions varies across different ecosystems and even within the same type of water bodies. Different mechanisms of methylation may occur in sediments and in water. Seasonal variations in MeHg production appear to be related to temperature, redox effects, seasonal changes in nutrient availability and Hg availability. Sulfur speciation and dissolved organic matter complexation are other important factors that are not well understood.

Knowledge Gaps

Despite the vast body of literature on the subject (348 publications cited in Ullrich et. al.,

2001), we still are unable to predict Hg methylation rates or the likely effects of environmental perturbations on methylation processes in natural systems due to the complexity of the systems described above. Since laboratory studies look at simple systems with few variables at a time, it also is difficult to directly compare the results of the laboratory studies published to date with the processes and rates in the natural environment. Knowledge gaps exist in the following areas:

Biotic vs. Abiotic Methylation: While it widely is believed that Hg methylation is biologically mediated, review of literature by Ullrich et. al. (2001) suggests that there may be more than one mechanism of MeHg formation. Abiotic methylation, particularly that mediated by humic substances, could be very important in wetlands and other ecosystems, but the significance of such processes in natural environments is unknown. Methylation vs. Demethylation: A portion of MeHg generated is demethylated by microorganisms, photochemical reactions, and other processes. Sulfate-reducing bacteria, which were considered to be important methylating agents, also now are considered to be active demethylators. It is not clear what environmental conditions cause these microbes to carry out methylation instead of demethylation.

Biomethylation: Review of the literature suggests that methylation can be caused by sulfate-reducing bacteria as well as a number of other types of bacteria that have not yet been identified. In the case of methylation by sulfate-reducing bacteria, the optimum sulfate concentrations required for methylation vary widely between different ecosystems and are difficult to predict. For example, bacteria in estuarine systems can methylate Hg at much higher sulfate concentrations than in freshwater systems. In addition, since bacteria that methylate Hg also are capable of demethylating, we are unable to predict biomethylation rates in natural systems.

Role of Organic Matter: Natural organic matter in soils, sediments, and water affect methylation in several ways. While natural organic matter can provide a stimulating effect on bacterial methylation in some systems, it may promote abiotic methylation in other systems or inhibit Hg methylation (due to strong complexation) under other environmental conditions. The exact role of organic matter in a given system often is ignored in predicting methylation rates. Because of the complex structure and composition of organic matter and due to the paucity of thermodynamic data for organic matter–Hg complexes, the role of organic matter on the speciation and bioavailability of Hg has not been well described or modeled.

Sulfur Chemistry: Sulfur speciation is an important variable in the methylation process. In addition to the role of sulfate on the methylation process, reduced sulfur can complex with Hg and form charged or uncharged Hg-sulfide complexes determining whether or not Hg becomes available to the microbes for methylation. Various stoichiometries of Hg-sulfide complexes have only been speculated, and competitive reactions between sulfide, organic matter, and Hg are not well defined.

Synergistic and Antagonistic Effects: From previous discussions it is apparent that each of the variables discussed above have multiple influences on the methylation and demethylation

process. For example, low concentrations of sulfate can limit microbial methylation, while high concentrations of sulfate can result in the formation of excess sulfide concentrations that complex with Hg and inhibit Hg methylation. Some of the above parameters can alter the effect of other influencing factors on Hg methylation. For example, pH and redox can directly affect methylation and bioaccumulation as well as altering Hg speciation, sulfur chemistry, and microbial activity. Due to the complex role of anyone of the above parameters on methylation, it is difficult to predict their combined effect in natural systems with existing models. There are many factors affecting methylation, but the current science is not adequate to resolve which factors are most important and allow models to move towards a more predictive capability. Research into factors affecting methylation is ongoing, however, with significant progress expected over the next several years.

METAALICUS Project: Some of the questions on the rates and factors governing Hg methylation may be answered by the Mercury Experiment to Assess Atmospheric Loading in Canada and the U.S. (METAALICUS) project currently underway at the Experimental Lakes Area (ELA) in western Ontario, Canada (Harris et. al., 2001). METAALICUS is a multi-disciplinary whole-ecosystem experiment in which a different isotope of Hg in the inorganic form (Hg(II)) is added to the upland, the wetland, and the lake surface to determine the relationship between atmospheric Hg loading and fish Hg concentrations. One of the goals is to determine how much of the newly deposited atmospheric Hg becomes bioavailable for methylation and biological uptake.

Implications of Knowledge Gaps

Any efforts to reduce MeHg concentration in fish tissue require a clear understanding of the processes that produce MeHg and factors that promote demethylation. Methylmercury production in aquatic systems is not a simple function of total Hg concentration in the system. Rather, as discussed above, it is affected by a number of complex, interrelated factors, which may result in a nonlinear relationship between total Hg and MeHg. Since any or all of these (or other) parameters can control methylation, either alone or in a complex interrelated process, ecosystems respond differently to changes in these parameters and, at present, there is no simple way to predict methylation rates in natural environments. In the Florida Everglades, for example, contrary to conventional wisdom, the percentage MeHg increases from north to south, opposite the gradients in nutrient, sulfate, and sulfide concentrations (Gilmour et. al., 1998). Regulatory measures, such as reducing Hg loading rates from atmospheric or point sources, will be less successful in reducing Hg levels in fish without greater understanding of these complex processes.

Marine and Farm-Raised Species

Because MMaps is designed to simulate natural freshwater systems, EPA does not have an appropriate method for assessing how a change in Hg deposition relates to a change in MeHg in fish tissue found in marine environments or farm-raised species.

Time Lag

In the NODA, EPA points out that MMaps does not account for the time lag between reducing Hg deposition and reducing MeHg concentrations in fish. In METAALICUS, newly deposited Hg appeared to be more available to bacteria to convert to MeHg than Hg that was in the system for longer periods of time (historically deposited Hg). EPA also observes that systems that receive most of their Hg input directly from the atmosphere may respond more rapidly to changes in emissions than those receiving significant inputs of Hg from the catchment area. EPA asks for information that can be used to extend or extrapolate the results of the METAALICUS experiment to other freshwater systems and information on Hg cycling and bioavailability in coastal and marine ecosystems.

The findings of the METAALICUS study, as reported in the scientific literature, are valuable because they provide empirical information on the relative importance of Hg sources to Hg cycling in the study lake (UIF). It should be noted, however, that the principal researchers have acknowledged that caution be used when extrapolating the METAALICUS results to other watersheds. Hintelmann et. al. (2002) state that:

> This conclusion [importance of newly deposited mercury to lake cycling and little runoff from the catchment area] is so far limited to terrestrial upland systems such as U1F. Further METAALICUS studies are underway investigating similar processes in wetlands and aquatic (lake) systems, keeping in mind that lakes receive mercury via direct atmospheric deposition as well as runoff. . . the overall contributions of old versus new mercury to mercury in runoff and the overall response time of watersheds to changes in atmospheric mercury deposition will most likely depend on the balance of wet and dry deposition as well as the fraction of rain events that are large enough to cause significant immediate runoff of newly deposited mercury.

While the METAALICUS study suggests a relatively short time lag between rates of Hg addition and lake compartment assimilation, the time lag of such a response will likely be unique to each watershed, and each water body within a watershed. This is because the factors that control the mass loading and mobilization of Hg to water bodies are unique.

Also, the quick response time observed in METAALICUS was observed only for the Hg isotope directly applied to the lake surface. EPA's screening model presently assumes that the same quick and linear response occurs with Hg deposition to uplands as well as water surfaces. The Florida, METAALICUS, Scandinavian, and all other field observations demonstrated quick responses (and then nonlinear or sub linear) only for directly applied Hg.

EPRI modeled the changes in fish Hg concentrations for four lakes (two in Wisconsin, one in Ontario, one in Florida) following a hypothetical reduction in inorganic Hg loading to the lakes, using an updated version of D-MCM. Different modeling scenarios of varying sediment depth (1-3 cm) and exchangeability of inorganic Hg to MeHg (availability of

inorganic Hg for methylation) were performed. The following table indicates the time required for fish Hg concentrations to reach 90 percent of the long-term steady state concentration:

Modeling assumptions (variables)	Lake response (time required for fish tissue Hg at 90 percent equilibrium concentration)
Sediment layer = 3 cm, 100 percent inorganic Hg available for methylation	40-160 yrs
Sediment layer = 1 cm, 100 percent inorganic Hg available for methylation (Pallette Lake)	39-122 yrs
Sediment layer = 1 cm, 10 percent inorganic Hg available for methylation	23 yrs

The modeling analysis indicates two important results: first, the response time between reductions in extemalloads and stable changed fish tissue concentration is NOT instantaneous (within 10 years). Secondly, key assumptions of within-lake processes (in this study, two variables affecting Hg availability in sediments) can have a pronounced effect on the predicted timing of long-term fish concentration change. This study provides important insights regarding EPA's expectations and assumptions of ecosystem response. In short, a relatively rapid response (as appears to be indicated by the METAALICUS study) would only be applicable to those types of lakes that the study was conducted at (northern temperate, oligotrophic). As indicated above, the technical literature is replete with examples showing that non-atmospheric load factors are largely responsible for the mobility and bioavailability of Hg.

Response:

EPA appreciates the commenter's input to the record. Please see the RIA.

4. Step 4: Fish Consumption and Human Exposure. EPA plans to address the relationship between reductions in methylmercury concentrations in fish tissue and reductions in human exposure through consumption. EPA plans on using the National Listing of Fish Advisories, supplemented b the National Fish Tissue Study, for information on methylmercury concentrations in fish and consumption data (including women of childbearing age, children, subsistence farmers and high-end consumers) to determine the relationship between reductions in concentrations in fish tissue and reductions in human exposure. EPA requested comment on whether the methylmercury fish concentration or fish consumption rates used in the Water Quality Criterion could be used for local, regional, or national assessments. EPA also requested data on the usefulness of the fish consumption data provided by the Clean Air Task Force et al (OAR-2002-0056-3460), Edison Electric Institute (OAR-2002-0056-2929), Electric Power Research Institute (OAR-2002-0056-2578), Forest County Potawatomi Community (OAR-2002-0056-2173), Minnesota Conservation Foundation et. al. (OAR-2002-0056-2415), and Southern Environmental Law Center (OAR-2002-0056-4222).

Comment:

One commenter (OAR-2002-0056-5422) said that EPA should consider the loss of health benefits associated with reduced fish consumption due to an overly conservative reference dose (RfD) for Hg blood levels in determining net health benefits due to the CAMR. The vast majority of health studies have concluded that the benefits of fish consumption by all segments of the general population far outweigh any effects due to blood Hg levels greater than EPA's RfD and at levels approaching the World Health Organization (WHO) level of concern. The use of the RfD as the basis for calculating fish warning Hg levels has resulted in a reduction in fish consumption and the related loss of health benefits to the public. The commenter supported the comments of the Center for Science and Public Policy in this regard (see OAR-2002-0056-5423).

Response:

Although EPA considers inclusion of the NFTS data extremely valuable in providing additional coverage for the study area, it is important to note that the majority of measured fish tissue concentrations were contributed by the NLFA and not by the NFTS. This fact partially addresses the commentor's concerns (i.e., the benefits analysis primarily reflects NLFA data with a smaller relative contribution from the NFTS dataset). However, several points can be made in response to concerns raised by the commentor regarding the NFTS data. Although NFTS composites do reduce variability (primarily related to fish size), because size information is available for many of the entries in NLFA, standardization using the NDMMFT model did have access to variability data related to size through the NLFA. The Great Lakes are not being included in the primary benefits analysis because of greater uncertainty in linking mercury deposition changes from power plants to fish tissue concentrations relative to lakes and rivers. The relatively small NFTS dataset is offset to some extent by inclusion of the larger NLFA dataset, although concerns of fish tissue sampling coverage (both spatially and temporally) do persist. For additional information on fish tissue datasets used in the benefits analysis, see Sections 10 and 14.

EPA agrees with the commentor that NLFA data (when reflecting areas of increased fishing activity) would be preferable to randomly collected data for purposes of supporting a benefits analysis. However, given the patchy nature of the NLFA and the variety of sampling protocols used by different states in collecting data included in the NLFA, EPA considers the NFTS data to be very useful in filling in gaps in coverages and in providing a consistent randomly-sampled dataset to augment the purposively sampled data contained in the NLFA.

As described in other responses, the Agency has high confidence in the RfD for methylmercury. EPA encourages the public to vary the species and sources of fish in order to obtain the benefits of fish consumption while avoiding elevated exposures to methylmercury. The fish advisory developed jointly with the Food and Drug Administration emphasizes the benefits of including fish in a healthy diet while informing the public on ways to reduce methylmercury exposure (http://www.epa.gov/waterscience/fishadvice/advice.html).

Comment:

Commenter OAR-2002-0056-5475 stated that the EPA defines Hg 'hot spot' as "a mercury deposition point dominated by utility plant contributions whose removal would result in fish tissue levels dropping from above to below the Fish Tissue Criterion of 0.3 ppm." The commenter found this definition to be self-limiting, implying no significant Hg impact on the environment when, in fact, the emitting facility may cause a Hg problem without including background Hg emissions. This is an absurd notion since it would allow for any increment of Hg emissions from a specific facility providing the background fish tissue Hg concentration is not below 0.3 ppm. For example, if the Hg fish tissue level for fish found near a utility plant is 1.0 ppm, yet the fish tissue Hg content from background emission sources would still be 0.35 ppm after removal of the Hg from the nearby utility plant, this area would not be considered a 'hotspot' since the fish would still remain over the 0.3 ppm concentration. This commenter stated that besides arbitrarily limiting the identification of local Hg impacts, this type of definition fails to take into account the substantial risk that could be posed by designating significantly elevated Hg concentrations as acceptable.

Response:

EPA has addressed the hot spots issue in the revision Federal Register notice and in the Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls in the docket.

Comment:

One commenter (OAR-2002-0056-5475) stated that the inability to quantify a facility's Hg speciation percentages on an on-going basis supports its concern that a cap-and-trade approach may be inappropriate compared to the standard MACT approach. The actual 'hot spots' that could be allowed to continue to exist as a result of a cap-and-trade approach may present unacceptable health risks to some of the citizens of Pennsylvania.

Response:

EPA appreciates the commenters concerns. Please see EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005) for a discussion of the importance of speciation for mercury capture. Also, please see Chapter 7 of the Regulatory Impact Analysis for a discussion of how we took speciation into account in our power sector modeling and see Chapter 8 for a discussion of how we took speciation into account in our air quality and deposition modeling. EPA has addressed the hot spots issue in the revision Federal Register notice and in the Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls in the docket.

Comment:

One commenter (OAR-2002-0056-5476) responded specifically to Step 4 of EPA's Proposed Revised Benefits Methodology: Fish Consumption and Human Exposure. This commenter believes that EPA's assumed consumption levels of 142.4 grams/day underestimates actual levels of fish consumed. The 1993 Survey of Tribal Spearers conducted by the Great Lakes Indian Fish and Wildlife Commission (GLIFWC) indicates that Ojibwe tribal members across Minnesota, Wisconsin and Michigan consume anywhere from 155.8 to 240.7 grams/day in conjunction with fall spearing. The spring spearing season can lead to consumption rates anywhere from 189.6-393.8 grams/day. The Leech Lake Band of Ojibwe Federally recognized Tribe with MCT membership has reported that they had determined that a fish consumption rate of 227 grams/day is possible under its treaty-protected fish harvesting right. The GLIFWC study also showed that 95 percent tribal respondents consumed at least one meal per week of the walleye caught during spearing and over 12 percent ate more than 7 meals per week. This consumption is very seasonal in nature, with consumption rate varying by as much as 150 grams/day between the fall and the spring but also has started to show more year-round harvest and consumption, as well as extended food storage through freezing. However, GLIFWC's survey is only a minimum threshold since the results are based solely on the those who have participated in the survey for some for traditional gatherers, these numbers may be higher since more traditional gatherers might not respond in a survey but are likely to consume more than the highest numbers the survey participants have reported in this survey.

The 1993 survey reveals that the average meal size may differ widely among groups. EPA assumes an average meal size of 6 ounces, or about 170 grams. However, GLIFWC finds that Tribal members responding to the survey and exercising their Fishing rights tend to eat an average meal ranging from 13-27 ounces, or about 369-766 grams; this range being only a minimum.

Mercury levels in fish caught and eaten locally may exceed levels found in commercially available fish or shellfish. U.S. Health and Human Services and EPA data show the commercially important fish like tuna, shrimp, salmon, and catfish can range in concentrations from 0.01-0.35 ppm. But recent EPA data for freshwater fish show that concentrations for important species like walleye, bass, trout, pike, and perch can vary from 0.25-1.03 ppm. This study further shows that, in a representative sampling of fish from U.S. lakes, 80 percent of predator fish levels exceeded US EPA's safe limit of 0.13 ppm for women. Fifty-five percent of all freshwater fish (predatory and non-predatory) sampled exceeded this level and 66 percent of all fish sampled exceeded US EPA's safe limit for children under three. By contrast, MCT used a 0.05 ppm trigger level for a 1 meal/week consumption advisory for sensitive populations.

In all instances, the numbers given above exceed EPA's assumed levels of consumption and Hg content, sometimes by large amounts. In further support of the commenter's viewpoint, EPA's document Fish Consumption and Environmental Justice: A Report Developed from the National Environmental Justice Advisory Committee Meeting of December 3-6, 2001 (2002 revised) states that although EPA's numbers are an improvement over previous figures, they do

not address consumption at the highest potential rates. The commenter urges EPA to take this new information into account when reviewing data about human exposure.

Both the EPA and the FDA have addressed Hg in fish tissue, but neither has done anything to address Hg in other food sources such as wild rice, moose, and wild birds. According to this commenter, Hg levels in some wild ducks occur at the same levels as in fish tissue. Although these results are from only a limited number of ducks and follow-up studies are needed, this is disturbing information that EPA may not be aware of. Because moose, ducks, and other animals eat primarily water plants, they are vulnerable to the effects of Hg poisoning. EPA does not attempt to address cumulative effects of toxic exposures in people who consume large quantities of other natural resources (e.g., venison, moose, bear, waterfowl, wild rice, blueberries). An analysis of local fish tissue samples typical of those consumed by the commenter were sampled, and commenter consumption advisories were set accordingly. For other MCT component Bands such as the Mille Lacs Band of Ojibwe Indians, the commenter has had to rely on those advisories set by MCT and those set by the State of Minnesota. Sensitive populations are advised to eat no more than one meal per month of most fish species, even if care is taken to eat only the smaller fish of the species. For those fishing for subsistence or cultural practice, this is a ridiculously small amount of fish. It is clear that most Band members are eating amounts in excess of this recommended level of consumption. The commenter does not believe this issue and the issue of persistence of toxic hazards created in the environment due to past weak or neglected resource protection were addressed in EPA's analysis.

The stationary-source industries, such as the electric utility and steam generating units, should not have the role to tell the commenter (via the IPM model) at what level standards should be set so they can deliver electricity to the commenter while fulfilling regulations at the least cost to themselves. It is up to EPA to determine how much Hg can be allowed in the environment and for utilities to use their business ingenuity to determine how they can best meet the standards EPA has set. Likewise, EPA should not tell the commenter how many and what type of fish can be consumed. Instead, the commenter should be able to tell EPA what its consumption levels are and EPA should make the fish safe for the commenter at those levels, preferably safe at any level. If this precedence is set, soon EPA will be calling upon the commenter to limit the amount of air it can breath and water it can drink. Limiting consumption of an otherwise healthy food source is not the answer.

The newspaper article "Mercury's Dangers Persist" (Milwaukee Journal Sentinel, Section G1: April 12, 2004) reported that even when people are aware of the dangers of eating fish from local waters, they often ignore the warnings. Likewise, the commenter believes that many indigenous peoples are unlikely to stop a subsistence-based, culturally rich tradition even though concentrations and number of toxic contaminants continue to increase. Despite warnings, some of these people will continue to fish and assume the risk of possibly suffering from ill health effect from toxins or else go hungry. Since Hg can be neither tasted nor smelled in fish meat, this may embolden some consumers to eat more than what is recommended as being safe.

Comments submitted by Electric Public Research Institute (EPRI) (Electric Public Research Institute, US EPA Document ID No. OAR-2002-0056-2578, June 26, 2004) addressing fish consumption rates of tribal people do not appear to be accurate. Since EPRI favors less stringent control options than the commenter does, it is highly inappropriate for EPRI to offer information about this subject. EPRI can have no information on this subject that is better than information that comes directly from the tribes. Although EPRI used NHANES and EPA data, it would be far more appropriate to let tribes describe their own consumption patterns, as these vary widely around the nation. EPRI comments that maternal cord blood results showing higher levels of Hg than originally protected have already been accounted for by including a single uncertainly factor for inter individual uncertainty into the derived Reference Dose. EPRI's model assumed a mean consumption rate of 3.7 gram/day and a maximum of 200 grams/day. Elsewhere, EPRI used EPA's mean consumption estimate of 14.3 and a 95th percentile rate of 61.63 grams/day (comparable to the NHANES numbers of 14 and 68.75 grams/day). The tribally specific data found by GLIFWC indicate that the actual numbers used should be much higher.

EPRI also made assumptions for the NHANES data about whether fish sampled were freshwater, marine, or farm-raised. The commenter prefers the use of locally generated data, rather than NHANES data; through GLIFWC and research conducted by MCT and by the commenter, the commenter has highly localized data that gives real answers about what tribal members eat. The commenter also prefers the use of local data to NHANES data as lake acidity varies widely from region to region and the lakes in Minnesota are of an acidity that readily promotes methylation of Hg. In order to get a truly accurate picture, why not use the best data that is available? EPRI estimated freshwater fraction versus marine fraction for Minnesota is also not indicative of what tribal members eat. The estimate of only 36.55 percent freshwater fish being eaten is far too low.

Comments submitted by Edison Electric Institute (EEI) (Edison Electric Institute, USEPA Document ID No. OAR-2002-0056-2929: June 29, 2004) state that fish consumption is not a problem in the U.S. because only a small portion of fish consumed by U.S. residents is affected by Hg deposition. The commenter strongly disagrees with this statement provided by EEI and instead would say a large portion of the population is consuming fish regardless of their actual Hg levels. The real question should be what is industry doing to ensure all our food-sources (and not just fish) are free of Hg and other toxins such that they will continue to have consumers in the future for their product.

First, if we examine the population numbers, the National Center for Health Statistics states that in the U.S. alone, 4.03 million babies were born in 2001. The 2000 Census shows that there were nearly 62 million women between the ages of 15 and 44. The Center for Disease Control states that in 2003, 70.9 percent of new mothers nursed in the hospital. Out of 4.03 million babies, that means that 2.86 million were breast-fed within their first few days of life. This totals up to 68.89 million sensitive humans being exposed to Hg on a daily basis. Breast-fed infants were counted twice, as they were exposed both in utero and while breast-feeding. Thus, 23 percent of the total U.S. population of 297.3 million is potentially at risk from eating

fish.

Second, local fish have been tested and found to contain Hg. Advisories have been issued for local fish consumption, not just by the commenter but by 44 states in the Union. Locally caught fish probably comprise 95 percent of all fish eaten by Band members. If EEI can include such egregiously incorrect statements as these, the rest of its comments are suspect.

EEI further states that most Americans, however, eat little fish. Half of all U.S. citizens eat no fish whatsoever and, of those who do, the weekly average consumption is about one-quarter pound. Nearly all this fish is store-bought ocean fish, which is unlikely to much Hg emitted from U.S. sources. EEI's comments, at least in this subject, are totally erroneous and unprofessionally naive. Catherine O'Neill's article Mercury, Risk, and Justice (34 ELR 11070, 12-2004) refutes this statement with data from NHANES III, which asserts that roughly 88 percent of all adults consume fish and shellfish at least once a month; and 1 percent consume fish daily. This study also shows that the population who eats fish frequently differs greatly from the population who eats fish less often. In short, Americans of color consume fish far more often than white respondents do, which puts these groups at special risks.

The EEI comments also assert that since a recent University of Rochester study has concluded that children in the Seychelles Islands appear to be unaffected by Hg exposure, that the utility industry should be let off the hook. The commenter believes that if the positions were reversed, EEI would also feel also the results of one study cannot totally refute the findings of many other studies. Although the results of the Seychelle study are surprising and show the need for further research, the whole of Hg study and regulation cannot be abandoned over it. In fact, the National Research Council of the U.S. National Academy of Sciences has concluded that the Faroe Islands study is more appropriate for use than the Seychelles study for deriving the Reference Dose (Clean Air Task Force, Natural Resources Defense Council, U.S. EPA Document ID No. OAR-2002-0056-3460: June 29, 2004). The commenter urges EPA to follow this advice.

The EEI supports the statement by the American Medical Association that because of the wide variations in the concentrations of Hg in fish and shellfish, it is possible to have the nutritional benefits of moderate fish consumption and avoid fish high in Hg (cit. Edison Electric Institute, US EPA Document ID No. OAR-2002-0056-2929: June 29, 2004). While this may be true of the typical consumer, subsistence level people do not have the option of spending money on store-bought fish or restaurant meals. The fish available to them are native species that come from local waters.

Response:

EPA appreciates the commenter's input to the record. Please see the RIA for a detailed description of EPA's modeling. Please also see EPA's discussion of hot spots in the revision Federal Register notice and in the Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for

Determining Effectiveness of Utility Emission Controls in the docket.

Comment:

One commenter (OAR-2002-0056-5447) noted that a significant reduction in Hg emissions from coal-fueled power plants will result in very little change in human exposures in the U.S. A reduction of 7 percent would result in a reduction in MeHg exposure for women of childbearing age by 0.5 to 0.75 percent.13

While Peabody supports EPA's goal of improving its science related to Hg deposition and bio-accumulation of Hg in fish, even a significant improvement in EPA's simplistic modeling will not change the basic conclusion that there will be little overall impact on either Hg deposition in the U.S. or on Hg levels in fish if Hg emissions are decreased from U.S. coal-fueled power plants. In contrast, as stated above, the high cost of compliance with these regulations will result in increased electrical costs to consumers and therefore increased mortality.

Response:

EPA appreciates the commenters input. Please see Chapter 11 of the Regulatory Impact Analysis for a description of the benefits of the CAMR.

Comment:

One commenter (OAR-2002-0056-5458) referred to the EPA and EPRI comment that existing freshwater fish data collected by the States may be biased because it is collected in areas of suspected contamination is misguided. The commenter has a fish sampling program that was developed to protect public health and has been collecting samples in areas where the only known Hg contribution is from atmospheric deposition. To suggest that the National Study of Chemical Residues of Lake Fish Tissue Study is superior for use in a Hg benefits determination over data collected by the State fish surveys is a serious error in judgement by the EPA. The EPA must analyze and integrate the existing fish concentration data collected by the States in any assessment of fish consumption. Contrary to the statement in the NODA that this data will overestimate exposure to anglers and their families, the commenter believes this data could be used to get a realistic estimate of exposure to anglers and their families, especially if the anglers are female and of child-bearing age.

The commenter is concerned about the use of the National Listing of Fish Advisories. If this database is to be used, it is acknowledged that a bias toward overestimation of Hg concentrations will occur on a national scale. However, other information is available within the states for other waters and/or species which could reduce or eliminate this bias. The data would be difficult, at best, to accumulate within the time frame necessary for consideration within this rule-making. A further confounding factor is a lack of uniformity among the states in the criterion used to cause placement of a health advisory on a fishery containing excessive Hg

concentrations. For example, many states use the EPA Hg criterion of 0.3 mg/kg, whereas some states, including New York, use the US Food and Drug Administration criterion of 1.0 mg/kg for the establishment of health advice for Hg in fish. Further, for states with a large number of waters (such as New York with over 7800 lakes, ponds and reservoirs, over 52,000 miles of streams, and 1.1 million acres of marine waters), it is physically and fiscally impossible to examine fish from all waters for Hg concentrations. Therefore, it is a certainty that the National Listing of Fish Advisories will significantly underestimate the numbers and acreage of waters containing fish with Hg in excess of the EPA criterion. Also, upon review of EPA's National Listing of Fish Advisories web-page, the commenter found the data presented for individual fish from New York waters are for the years 1990-1997 only, thus, it is somewhat dated, limited and incomplete. The listing of health advisories is current through 2003, but of little value for EPA's purposes (i.e., to estimate MeHg concentrations in fish and consumption rates of such fish) because actual Hg concentrations are not given and only species with Hg concentrations above the advisory criterion are listed.

The National Study of Chemical Residues in Lake Fish Tissue was designed to provide a statistical representation (with stratified random sampling by size of lakes) of the relative distribution of Hg in fish throughout the US, although it excludes the Great Lakes. The study was designed to select one composite of a bottom dwelling fish species and one composite of a predator fish species. Recommended bottom dwelling species included brown bullhead or similar catfish species, carp, or white sucker. All these bottom dwelling species are not good accumulators of Hg since they represent lower trophic levels, typically are not predatory, and often do not show substantial accumulations of Hg even when concentrations may be elevated in other species. The predatory species recommended in the project design include largemouth and smallmouth bass and walleye, among others, which represent top level predator species that are good indicators of Hg concentrations within a waterbody, provided they are present within the water. Not all waters sampled will contain one or more of these predator species. Other predator species included in the study (several species of trout plus northern pike and black or white crappie) provide indications of Hg concentrations that are intermediate between the bottom dwelling fish and the top predators.

Use of the National Study of Chemical Residues in Lake Fish Tissue results could present bias based on how the data is presented. First, the five Great Lakes are excluded, and each of the Great Lakes are known to contain species of fish which exceed the EPA Hg criterion of 0.3 mg/kg, therefore, millions of acres of water may be excluded from consideration, i.e., 2.65 million acres in New York alone. Second, the relative proportion of lakes adversely affected by Hg could be characterized as either numbers of waters or surface acreage. Characterization by both methods should be incorporated into an evaluation to give a more accurate description of impact and potential benefits to be derived. Other concerns that the commenter has about the utility of this study as it relates to EPA's goals include: 1) measurements of variability in the data will be limited because samples are composites (i.e., only one data record for each species per lake); 2) sample composites limit assessments to one size class of fish per lake, restricting the chance to examine fish size-Hg concentration relationships; 3) this study will only provide a very generic regional assessment of fish Hg concentrations because less than 0.5 percent (n=25)

of the lakes in the state were sampled and the distribution of those lakes selected do not reflect the distribution of lakes within the state (lakes in the Adirondacks, a six million acre area known to have Hg issues, represent over 60 percent of lakes in New York while only 36 percent of the national study lakes in New York were from the Adirondacks); 4) the analysis of only two species per lake is restrictive and the data are further diluted because species selection varied by lake; and 5) overall this was a screening-level study with limited application for determining important regional and size/species-related Hg concentration patterns in a variety of popular and edible fish species.

The commenter is concerned with some of the potential assumptions that can be used to determine human exposure and requests that the EPA adhere to the maximum individual risk (MIR) concept as discussed in the Residual Risk Report to Congress. In the case of MeHg exposure, the MIR represents the highest estimated risk to an exposed individual based on realistic high-end consumption and fish Hg concentration inputs. The use of the average Hg concentration for the average fish combined with the average fish consumption rate will result in an average benefit determination that will underestimate the benefits of reducing Hg emissions. The EPA exposure handbook has fish consumption rate for the 95th percentile at 25 grams per day for non-subsistence people and 170 grams per day for subsistence fish eaters. The EPA Methyl Mercury Water Quality Criterion uses freshwater fish consumption rates of 156.3 grams/day for children, 165.5 grams /day for women of child-bearing age and 17.5 grams/day for adults in the general population. The benefits analysis should reflect the MIR concept and use the high-end consumption parameters for fish consumption for women of childbearing age and children to insure a proper accounting of the benefits of reducing Hg emissions for this sector of the population.

Response:

Please see Chapter 5 of the RIA for a discussion of concentrations of mercury in fish. Please also see the Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units and the Removal of Coal- and Oil-fired Electric Utility Steam Generating Units from the Section 112(c) List for a discussion of the Agency's rationale for not proceeding under Section 112 Notice and in the Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls in the docket.

Comment:

One commenter (OAR-2002-0056-5535) presented below, several specific issues that would benefit from such careful peer review. The commenter did not intend this list to be comprehensive, but merely included it to illustrate that the agency must address critical scientific issues prior to making changes to its deposition and watershed models or conducting other components of the proposed analyses. This overview serves to demonstrate that it would be foolish to hold up final Hg regulations while EPA further investigates certain technical issues

concerning the emissions, fate, and toxicity of Hg from power plants.

Hg deposition and estuarine and marine species. Although EPRI has conducted an assessment of the impact of Hg deposition on marine and estuarine fish species, this is a particular area where EPA needs to consult the broader scientific community.

The commenter urged the agency to give additional weight to the findings of the METAALICUS project as the researchers on this team are internationally recognized Hg experts conducting unbiased scientific research. The commenter noted that EPA was quick to emphasize that results from METAALICUS were ongoing and still being refined while offering no such caution when describing PERI's conclusions on numerous scientific issues (e.g., plume transformation, global inventories, global transport of Hg, marine impacts, human exposure, etc.)

The Mercury Report to Congress contains a large amount of data on high-end fish consumers. EPA should augment this information with more recent regional studies on fish consumption patterns such as have been conducted in New England.

The commenter continued to take issue with the current EPA definition of hot spots which is limited to levels of Hg in fish tissue that would cause the human population to exceed the RfD. Given the human and ecological health risks associated with Hg exposure, the definition of hot spots should be recast to include local, regional and national hot spots as identified by (1) hot spots in deposition, (2) hot spots in water, and (3) hot spots in biota.

New research regarding the extent of Hg in water, fish and wildlife and the occurrence of hot spots in the Northeast U.S. is forthcoming in the journal Ecotoxicology. EPA should incorporate these findings is any new assessments of the impacts of Hg emissions.

The commenter stated that despite the scientific uncertainties of the broad assessment that EPA has described, the agency can still improve the benefits assessment in the short term for the purpose of preparing a Regulatory Impacts Analysis for the final rule. Specifically, an assessment and monetization of cardiovascular effects in children and adults and the loss of IQ points in children can be accomplished with the data at hand concerning Hg blood levels in the U.S.

Response:

Please see Chapter 3 of the CAMR Regulatory Impact Analysis for a detailed discussion of mercury in the environment, including an assessment of the response time for systems after a change in mercury deposition. Please also see Section 8 for a discussion of the change in mercury deposition based on air quality modeling and Chapters 11 for a benefits analysis of the CAMR. Please also see the *Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units and the Removal of Coal- and Oil-fired Electric Utility Steam Generating Units from the Section 112(c) List for a discussion of the Agency's rationale for not proceeding under Section 112 Notice and in the*

Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls in the docket.

Comment:

The commenter (OAR-2002-0056-5465) stated that additionally, they would like to address Part II of the NODA, "Step 4 of EPA's Revised Benefits Methodology: Fish Consumption and Human Exposure." Again, note that by focusing its comments, the commenter does not mean to suggest that this is the only step in EPA's proposed method that warrants critique.

As EPA noted, consumption of fish was the primary pathway for human exposure to MeHg. As such, two sets of factors became important to determining human exposure: those describing the concentration of MeHg in fish tissue and those describing fish consumption practices for humans.

Methylmercury Concentration

In the NODA, EPA indicated that it is considering looking to the National Study of Chemical Residues in Lake Fish Tissue (also referred to as the National Fish Tissue Study (NFTS)), given its concern that data from the EPA's National Listing of Fish Advisories (NLFA), which is collected by state agencies, may be "biased." Specifically, EPA argued that the fact that states generally collect fish tissue Hg data from (a) "areas of increased angling activity," and (b) "areas of suspected contamination" means that this data may "overestimate exposure to anglers and their families." This concern is largely misplaced. First, from a public health perspective, it is entirely appropriate to sample from areas likely to be fished, i.e., "areas of increased angling activity," in order to determine the MeHg concentration in species likely to be consumed by humans. To prefer a random sampling method (as undertaken in the NFTS) is to misfocus the relevant inquiry. If the waterbodies sampled are not fished by humans, then humans are not going to be exposed via fish in those waterbodies. The effect, of course, is to dilute the relevant value for mean MeHg concentration in fish tissue, resulting in an estimate of exposure that is inaccurate and thus scientifically unsound. On a related note, it makes sense to consider, additionally, the concentration in the tissue of fish caught in areas once favored by humans but no longer fished due to advisories warning of contamination. Because humans would fish in these areas but for unaddressed contamination, it is reasonable to set environmental standards at levels protective of consumption here. Second, although some states and tribes initially began their data collection efforts with waterbodies that they believed to be contaminated, it should be kept in mind that many states and tribes have been gathering this data for some time, and have now sampled broadly and extensively from the waterbodies within their respective jurisdictions. In fact, the commenter urged the EPA to consult with the Great Lakes Indian Fish and Wildlife Commission (GLIFWC) about data they have gathered that documents MeHg concentration in the tissue of locally consumed species at levels greater than suggested by state or federal data.

Fish Consumption Rates and Practices

EPA stated in the NODA that it is seeking information on fish consumption rates by different affected populations, particularly in the eastern half of the U.S. The commenter referred EPA to the analysis of various groups' fish consumption practices conducted by Professor O'Neill (in the attached article, see OAR-2002-0056-5465) and to the fish consumption rates for the various Ojibwe and other Great Lakes tribes cited therein. The commenter also referred EPA to the discussion and studies in the report of the National Environmental Justice Advisory Committee, Fish Consumption and Environmental Justice.

EPA asked specifically whether the fish consumption rates used in the Water Quality Criterionx or produced in the Peterson, et al., study are appropriate for assessing the effects on, inter alia, tribal populations. In the first place, the commenter emphasized that the only ones with the knowledge to respond to this question are the affected tribes themselves. Thus, if EPA is to produce an accurate and defensible assessment, it must pose this question directly to the various tribes. Moreover, EPA should honor its commitment to consult with tribes on a government-to-government basis on issues, such as this, that affect tribal rights and resources.

Although the commenter deferred to tribes' individual responses to the above question, it nevertheless noted that the fish consumption rates used by the Water Quality Criterion (produced by the national CSFII study) and produced by the local Peterson, et. al., study are markedly lower–more than an order of magnitude lower - than the fish consumption rate produced by a 1993 GLIFWC survey of tribal spearers (189.6 to 393.8 grams/day in the spring) and the fish consumption rate adopted by the Leech Lake Band, one of the Minnesota Chippewa Tribe members (227 grams/day). These differences and their implications are elaborated in the attached article by Professor O'Neill. Further (see OAR-2002-0056-5465) , a host of other aspects of tribal members' different fish consumption practices (e.g., "acute" consumption in accordance with seasonal or cultural practices; different average meal size; different species consumed) are relevant to an assessment of exposure and must be considered by EPA. Several of these aspects are discussed in the attached article by Professor O'Neill (see e-docket OAR-2002-0056-5465); in addition, CPR refers EPA to discussions by tribal commenters such as the Fond du Lac Tribe. xii As a general matter, in assessing the effects on tribal populations, EPA should eschew data from studies that are national in focus (such as the CFSII study) and/or are non-tribally conducted (such as the Peterson, et al., study), in favor of studies of the relevant tribal population conducted by the tribe/the relevant intertribal association (or at least suggested by the tribe in consultation). Such a preference would produce more accurate and therefore scientifically defensible results. In this vein, the commenter found EPRI's suggested fish consumption rates particularly ill conceived. PERI purports to construct "local" fish consumption rates, but does so by weaving together a host of assumptions that simply do not comport with actual local practice, that serve chiefly to underestimate exposure (e.g., PERI assumes a fish MeHg concentration of 0.12 mg/kg MeHg), and that work backward from NHANES data on blood Hg levels to fabricate likely consumption rates for each state - a highly questionable method in the face of numerous empirical studies documenting actual local consumption rates.

Finally, the commenter noted that EPA needed to account for the fact that the tribal consumption rates described in the Peterson, et al., study may reflect current consumption levels that are artificially low. As the Peterson study itself notes, some tribal members may have already altered their fishing and fish consumption practices to some degree in view of the fish consumption advisories issued by the states and the tribes. To the extent this is the case, the fish consumption rate that is generated by a survey such as that conducted by Peterson does not reflect what tribal members would consume, were the fish not contaminated with Hg. Patrick West, et al., termed this the "suppression effect:" that is, the fish consumption rate revealed by surveys in these instances reflects a "suppressed" rate of consumption. This point applies with particular force to tribes, who have treaty guarantees to a certain level of consumption. Even if tribal members have had to forego fish recently because fish have been allowed to become contaminated, they are entitled not to do so; thus environmental standards should be set to protect consumption at the higher, treaty-guaranteed level of consumption, not the lower, suppressed level of consumption. Again, tribes will be uniquely positioned to be able to identify and account for suppression effects for their populations; as such, tribally conducted studies or tribally interpreted data are to be preferred.

Response:

EPA agrees that for some situations (e.g., commenter examples) the value 142.4 may be an underestimate of fish consumption. This is the value that the Agency recommends in its water quality standards program to States with high-consuming sub-populations, in lieu of site-specific data when those states are faced with developing a water quality standard for methylmercury that is protective of the fish consumption use of state waters demonstrated by those sub-populations. Where a state has local information indicating higher rates of fish consumption than 142.4, it is recommended that they use it. In the benefits analyses performed for this rule, several consumption scenarios were considered based on the available data pertinent to the population modeled (recreational anglers), but the value of 142.4 g/day was not used.

The EPA has included four potentially high-risk populations in the RIA, including: (a) high-end recreational fisher anglers (with consumption rates at or above the 95th percentile for this group), (b) economically disadvantaged high-end consumers with poverty-status income and fish consumption rates at or above the 95th percentile for freshwater anglers, (c) Hmong in Minnesota and Wisconsin and (d) Chippewa in Minnesota, Wisconsin and Michigan. These special population are intended to provide coverage for groups of individuals who through choice, necessity or socio-cultural practices consume relatively high levels of self-caught freshwater fish. Inclusion of these four special populations is also intended to support consideration of distributional equity in relation to EGU-based environmental regulation (i.e., would a subset of the US population benefit disproportionately from regulations to reduce mercury emissions from EGUs)?

Fish consumption rates for all four special populations have been developed based on peer-reviewed survey data that are representative of the particular group of interest. In the case of the Chippewas, EPA has used a mean value obtained from the literature (see RIA Chapter 10 for additional details). However, it was not possible to identify a high-end percentile

consumption rate based on peer-reviewed literature and consequently, the mean consumption rate was used in the benefits analysis without consideration for variability in fish consumption rates across individuals. However, in response to information provided in NODA comments (including that provided by this commentor), EPA has conducted a sensitivity analysis for high-end fish consumption by the Chippewa population using (a) the maximum delta fish tissue concentration (for Walleye) modeled in states where Chippewa are located for the RIA for Option 1 and Option 2 (i.e., the maximum change in MeHg fish tissue concentrations modeled in Michigan, Wisconsin or Minnesota under CAMR Options 1 and 2) and (b) the maximum seasonal fish consumption rate provided in the NODA comments (i.e., 393.8 g/day). The results suggest that total IQ reductions under Option 1 and 2, even under these conservative assumptions (i.e., highest change in mercury fish tissue concentrations under Option 1 and Option 2 and the highest seasonal fish consumption rate), are relatively low at 0.32 IQ points per child. This relatively low IQ benefit for this conservative scenario reflects the fact that, while states where the Chippewa are located may have relatively high absolute (total) MeHg concentrations in target fish species, modeled EGU deposition over these areas is relatively low and consequently, CAMR is likely to produce relatively small changes in mercury fish tissue concentrations compared with other areas where EGU deposition is higher (e.g., the Ohio river valley). These findings argue against a distributional equity concern for the Chippewa in this portion of the study area (although this conclusion needs to be considered in the context of the overall precision and specificity of the benefits model used in this RIA which is not intended for site-specific analysis and was developed for application at the regional-level).

EPA acknowledges that states contributing data to the NLFA may use different protocols that result in mercury fish tissue concentrations having different degrees of bias (e.g., focus on most impacted waterbodies versus waterbodies most heavily fished). The degree of uncertainty and potential relevance in adversely impacting the RIA will depend on the specific protocol being considered. If a state focuses fish sampling on areas experiencing heavy fishing activity, then this will actually benefit the economic analysis by contributing fish tissue measurements from waterbodies experiencing fishing activity. Conversely, states that focus on areas believed to have a mercury contamination problem, could bias the NLFA dataset in a conservative direction if those waterbodies are not fished relative to other less-impacted waterbodies. Given potential concerns over the NLFA and potential bias resulting from the individual state's sampling protocols, EPA completed a statistical comparison of the NLFA and the NFTS datasets (the NFTS uses a rigorous statistical sampling procedure to provide unbiased coverage for waterbodies). This statistical comparison showed that the NLFA and NFTS datasets were indistinguishable statistically except at the extreme high end, where there was some conservative bias identified in the NFTS. These findings support the use of the NLFA (along with the NFTS) in conducting national or regional benefits analyses, since these analyses focus on generalized trends in mercury fish contamination. However, EPA acknowedges that assessments of extreme high-end exposure and risk could be biased somewhat high if the NLFA data are used. However, it is important to reiterate that, if the NLFA bias reflects waterbodies where fishing activity is likely, then this identified high-end bias may not be problematic and indeed, could be preferred (i.e., it would not represent true bias).

Although EPA considers inclusion of the NFTS data extremely valuable in providing

additional coverage for the study area, it is important to note that the majority of measured fish tissue concentrations were contributed by the NLFA and not by the NFTS. This fact partially addresses the commentor's concerns (i.e., the benefits analysis primarily reflects NLFA data with a smaller relative contribution from the NFTS dataset). However, several points can be made in response to concerns raised by the commentor regarding the NFTS data. Although NFTS composites do reduce variability (primarily related to fish size), because size information is available for many of the entries in NLFA, standardization using the NDMMFT model did have access to variability data related to size through the NLFA. The Great Lakes are not being included in the primary benefits analysis because of greater uncertainty in linking mercury deposition changes from power plants to fish tissue concentrations relative to lakes and rivers. The relatively small NFTS dataset is offset to some extent by inclusion of the larger NLFA dataset, although concerns of fish tissue sampling coverage (both spatially and temporally) do persist. For additional information on fish tissue datasets used in the benefits analysis, see Sections 10 and 14.

Comment:

One commenter (OAR-2002-0056-5455), in reference to fish consumption and human exposure, responded specifically to Step 4 of EPA's Proposed Revised Benefits Methodology: Fish Consumption and Human Exposure. The commenter believed that EPA's assumed consumption level of 142.4 grams/day underestimates actual levels consumed by the commenters. A survey by the Great Lakes Indian Fish and Wildlife Commission (GLIFWC) indicated that members of Ojibwe Great Lakes tribes consumed anywhere from 155.8-240.7 grams/day in conjunction with fall spearing. The spring spearing season can lead to consumption rates anywhere from 189.6-393.8 g/day. The Leech Lake Band, one of the Minnesota Chippewa Tribe member bands, has determined that a fish consumption rate of 227 g/day is possible under its treaty-protected fish harvesting right. The GLIFWC study also showed that 95 percent tribal respondents consumed at least one meal per week of the walleye caught during spearing and over 12 percent ate more than 7 meals per week. This consumption is very seasonal in nature, with consumption rates varying by as much as 150 g/day between the fall and the spring. The survey also reveals that the average meal size may differ widely among groups. EPA assumes an "average" meal size of 6 ounces, or about 170 grams. However, GLIFWC finds that tribal fishers tend to eat an "average" meal ranging from 13-27 ounces, about 369-766 grams. EPA should adjust their analysis accordingly.

Mercury levels in fish caught and eaten locally may exceed levels found in commercially available fish or shellfish. U.S. Health and Human Services and EPA data show that commercially important fish like tuna, shrimp, salmon, and catfish can range in MeHg concentrations from 0.01-0.35 parts per million (ppm). But recent EPA data for freshwater fish show that MeHg concentrations for important species like walleye, bass, trout, pike, and perch can vary from 0.25-1.03 ppm. This study further shows that, in a representative sampling of fish from U.S. lakes, 80 percent of predator fish levels exceeded EPA's safe limit of 0.13 ppm for women. Fifty-five percent of all freshwater fish (predatory and non-predatory) sampled exceeded this level and 76 percent of all fish sampled exceeded EPA's safe limit for children

under three. By contrast, the commenter used a 0.05 ppm trigger level for a "1 meal/week" consumption advisory for sensitive populations.

In all instances, the numbers given above exceed EPA's assumed levels of consumption and Hg content, sometimes by large amounts. In further support of our viewpoint, EPA's document Fish Consumption and Environmental Justice: A Report Developed from the National Environmental Justice Advisory Committee Meeting of December 3-6, 2001 (2002 revised), states that although EPA's numbers are an improvement over previous figures, they do not address consumption at the highest potential rates. Please take this new information into account when reviewing your data about human exposure.

EPA made no attempt to address cumulative effects of toxic exposures in people who consume large quantities of other natural resources (i.e., venison, moose, bear, waterfowl, wild rice, blueberries), although this would be a scientifically sound idea if EPA truly wants to protect sensitive members of the population. An analysis of local fish tissue samples typical of those consumed by the commenters were analyzed and Reservation consumption advisories set accordingly. Sensitive populations are advised to eat no more than one meal per month of most fish species, even if care is taken to eat only the smaller fish of the species. For those fishing for subsistence or cultural practice, this is a ridiculously small amount of fish. It is likely that most commenters were eating amounts in excess of this recommendation. Also, because the fish are harvested with nets, it is impossible to target "safe" sizes. This issue was also not addressed in EPA's analysis.

As alluded to in the previous paragraph, EPA has addressed Hg in fish tissue but has done nothing to address Hg in other food sources such as wild rice, moose, and waterfowl. The commenter had found that Hg levels in some wild ducks occur at the same levels as in fish tissue. Although these results are from only a limited number of ducks and follow-up studies are needed, this is disturbing information that EPA may not be aware of. Because moose, ducks, and other animals eat primarily water plants, they are vulnerable to the effects of Hg poisoning.

It should not be utility's role to tell the public (via the IPM model) at what level standards should be set so they can deliver electricity to us while fulfilling regulations at the least cost to themselves. It is up to EPA to determine how much Hg can be allowed in the environment and for utilities to use their business acumen to determine how they can best meet the standards EPA has set. Likewise, EPA should not tell tribes how many and what type of fish they can consume. Instead, the tribes should be able to tell EPA what their consumption levels are and EPA should make the fish safe for them to consume at those levels. If this precedence is set, soon EPA will be calling upon us to limit the amount of air we can breathe and water we can drink. Limiting consumption of an otherwise healthy food source is not the answer.

Studies showed that even when people were aware of the dangers of eating fish from local waters, they often ignored the warnings. Likewise, the commenter believed that many tribal people are unlikely to give up a subsistence-based, culturally rich tradition even though warnings have been issued. Some of these people will either continue to fish or go hungry.

Since Hg can be neither tasted nor smelled in fish meat, this may embolden some consumers to eat more than is safe. Furthermore, most people are unaware of recent findings indicating that consumption of Hg-contaminated fish can lead to heart disease. Both men and those women not of childbearing age may be over consuming based on their ignorance of this information.

Comments submitted by PERI addressing fish consumption rates of tribal people are not accurate. Since PERI favors less stringent control options than the tribes do, it is highly inappropriate for PERI to offer information about this subject. PERI can have no information on this topic that is better than information that comes directly from the tribes. Although PERI used NHANES and EPA data, it would be far more appropriate to let tribes describe their own consumption patterns, as these vary widely around the nation. PERI comments that maternal cord blood results showing higher levels of Hg than originally thought have already been accounted for "by including a single uncertainly factor for inter-individual uncertainty into the derived Reference Dose." The commenter wonders why Reference Doses got only one factor of uncertainty while the MACT standard calculated by EPA contains several factors to correct for variability in MACT floor calculations, compliance methods, fuel types, etc.. EPRI's model assumed a mean consumption rate of 3.7 g/day and a maximum of 200 g/day. Elsewhere, PERI used EPA's mean consumption estimate of 14.3 and a 95th percentile rate of 61.63 g/day (comparable to the NHANES numbers of 14 and 68.75 g/day). The tribally specific data given earlier in this letter indicated that the actual numbers used should be much higher to account for seasonal variation. While the commenter assumed a daily consumption rate of 60 g/day in setting its water quality standards, this rate of consumption is believed to be far more common than what would occur at the 95th percentile."

PERI also made assumptions for the NHANES data about whether fish sampled were freshwater, marine, or farm-raised. Again, the commenter preferred the use of locally-generated data, rather than NHANES data, because such localized data gives real answers about what tribal members eat, which are better than projections from non-tribal people. In addition, local data helps capture lake acidity variability that occurs from region to region. As lakes in northern Minnesota are of an acidity that readily promotes methylation of Hg, the commenter believed it is essential that local data be used as much as possible. In order to get a truly accurate picture, why not use the best data that is available? EPRI's estimated "freshwater fraction versus marine fraction" for Minnesota is also not indicative of what tribal members eat. The estimate of only 36.55 percent freshwater fish (of total fish consumed) is far too low.

Comments submitted by Edison Electric Institute (EEI) stated that fish consumption is not a problem in the U.S. because only a small portion of fish consumed by U.S. residents is affected by Hg deposition. A large portion of the population is consuming fish, and those fish are contaminated with Hg. First, let's look at population numbers. The National Center for Health Statistics states that, in the U.S., 4.03 million babies were born in 2001. The 2000 Census shows that there were nearly 62 million women between the ages of 15 and 44. The Center for Disease Control states that in 2003, 70.9 percent of new mothers nursed in the hospital. Out of 4.03 million babies, that means that 2.86 million were breast-fed within their first few days of life. This totals up to 68.89 million sensitive humans being exposed to Hg on a

daily basis. Breast-fed infants were counted twice, as they were exposed both in utero and while breast feeding. Thus, 23 percent of the total U.S. population of 297.3 million is potentially at risk from eating fish. Second, local fish have been tested and found to contain Hg in levels that exceed EPA recommendations. Advisories have been issued for local fish consumption, not just by the commenter but also by 44 states in the Union. Locally caught fish probably comprise 95 percent of all fish eaten by Band members. If EEI can include such egregiously incorrect statements as these, the rest of its comments are suspect.

EEI further claims, "Most Americans, however, eat little fish. Half of all Americans eat no fish whatsoever and, of those who do, the weekly average consumption is about one quarter pound. Nearly all this fish is store-bought ocean fish, which is unlikely to contain much Hg emitted from U.S. sources". This statement is totally erroneous and downright bizarre. Catherine O'Neill's article refutes this statement with data from NHANES III, which asserts "roughly 88 percent of all adults consume fish and shellfish at least once a month; and 1 percent consume fish daily." This study also shows that composition of the group who eats fish frequently differs greatly from the group who eats fish less often. In short, Americans in minority groups consume fish far more often than white respondents do, putting these groups at higher risk.

The EEI comments also assert that since a recent University of Rochester study has concluded that children in the Seychelles Islands appear to be unaffected by Hg exposure, the utility industry should be let off the hook. As I'm sure EEI would feel if the positions were reversed, the results of one study cannot totally refute the contradictory findings of many other studies. Although the results of the Seychelles study are surprising and show the need for further research, the whole of Hg study and regulation can't be abandoned over it. In fact, the National Research Council of the U.S. National Academy of Sciences has concluded that the Faroe Islands study is more appropriate for use than the Seychelles study for deriving the Reference Dose. The commenter urged EPA to follow this advice rather than the biased comments from EEI.

The EEI supports the statement by the American Medical Association that "because of the wide variations in the concentrations of Hg in fish and shellfish, it is possible to have the nutritional benefits of moderate fish consumption and avoid fish high in Hg." While this may be true of the typical consumer, subsistence level people do not have the option of spending money on store-bought fish or restaurant meals. The fish available to them are native species that come from local waters.

So, in summary, the commenter did not agree with the fish consumption rates used in this rulemaking. The Water Quality Criterion uses a consumption rate of 17.5 g/day (or lower), which has been shown to be too low for tribal people. The commenter also was suspicious of the consumption rates given in Peterson, et. al., because they do not agree with data obtained from GLIFWC and the Leech Lake Band. The commenter had not had sufficient time to thoroughly review the Peterson study, the commenter are simply wary of its results. It could be that the people surveyed have already changed their consumption habits to account for Hg

contamination. If so, it is an example of an indirect curtailing of treaty rights and is unacceptable. The relatively low consumption patterns evidenced by the study may also be a function of efforts made by the Wisconsin Department of Natural Resources and by the specific tribal governments to inform people of consumption advisories. As an Environmental Justice aside, let me point out the Peterson study's finding that Hg levels were highest among the unemployed.

The NODA also seeks comment on EPA's plan to use National Fish Tissue Study (NFTS) values for methylHg concentrations in fish. EPA favors the use of NFTS data over National Listing of Fish Advisories (NLFA) data because the former were gathered by random sample while the NLFA data are gathered from areas of increased angling activity and from areas of suspected contamination (as explained in the NODA). The commenter believed this reasoning is exactly backward. If one wants to protect the most sensitive members of the population, worst-case scenarios must be considered. That means looking at those who eat the highest quantities of fish and those who eat the most heavily contaminated fish. The commenter believed this is highly appropriate based on a public health perspective. Second, GLIFWC data suggests levels of contamination higher than those put forth by EPA.

Response:

EPA agrees that for some situations (e.g., commenter examples) the value 142.4 may be an underestimate of fish consumption. This is the value that the Agency recommends in its water quality standards program to States with high-consuming sub-populations, in lieu of site-specific data when those states are faced with developing a water quality standard for methylmercury that is protective of the fish consumption use of state waters demonstrated by those sub-populations. Where a state has local information indicating higher rates of fish consumption than 142.4, it is recommended that they use it. In the benefits analyses performed for this rule, several consumption scenarios were considered based on the available data pertinent to the population modeled (recreational anglers), but the value of 142.4 g/day was not used.

EPA has included four potentially high-risk populations in the RIA, including: (a) high-end recreational fisher anglers (with consumption rates at or above the 95th percentile for this group), (b) economically disadvantaged high-end consumers with poverty-status income and fish consumption rates at or above the 95th percentile for freshwater anglers, (c) Hmong in Minnesota and Wisconsin and (d) Chippewa in Minnesota, Wisconsin, and Michigan. These special population are intended to provide coverage for groups of individuals who through choice, necessity or socio-cultural practices consume relatively high levels of self-caught freshwater fish. Inclusion of these four special populations is also intended to support consideration of distributional equity in relation to EGU-based environmental regulation (i.e., would a subset of the US population benefit disproportionately from regulations to reduce mercury emissions from EGUs)?

Fish consumption rates for all four special populations have been developed based on peer-reviewed survey data that are representative of the particular group of interest. In the case of the Chippewa, EPA has used a mean value obtained from the literature (see RIA Chapter 10

for additional details). However, it was not possible to identify a high-end percentile consumption rate based on peer-reviewed literature and consequently, the mean consumption rate was used in the benefits analysis without consideration for variability in fish consumption rates across individuals. However, in response to information provided in NODA comments (including that provided by this commenter), EPA has conducted a sensitivity analysis for high-end fish consumption by the Chippewa population using (a) the maximum delta fish tissue concentration (for Walleye) modeled in states where Chippewa are located for the RIA for Option 1 and Option 2 (i.e., the maximum change in MeHg fish tissue concentrations modeled in Michigan, Wisconsin or Minnesota under CAMR Options 1 and 2) and (b) the maximum seasonal fish consumption rate provided in the NODA comments (i.e., 393.8 g/day). The results suggest that total IQ reductions under Option 1 and 2, even under these conservative assumptions (i.e., highest change in mercury fish tissue concentrations under Option 1 and Option 2 and the highest seasonal fish consumption rate), are relatively low at 0.32 IQ points per child. This relatively low IQ benefit for this conservative scenario reflects the fact that, while states where the Chippewa are located may have relatively high absolute (total) MeHg concentrations in target fish species, modeled EGU deposition over these areas is relatively low and consequently, CAMR is likely to produce relatively small changes in mercury fish tissue concentrations compared with other areas where EGU deposition is higher (e.g., the Ohio river valley). These findings argue against a distributional equity concern for the Chippewa in this portion of the study area (although this conclusion needs to be considered in the context of the overall precision and specificity of the benefits model used in this RIA which is not intended for site-specific analysis and was developed for application at the regional-level).

The National Research Council has identified fish consumption as the primary pathway of concern for exposure to methylmercury in the United States and consequently, the RIA has focused on this exposure pathway and has not considered other dietary categories such as non-fish meat and vegetables. EPA does recognize that additional dietary pathways may contribute to overall methylmercury exposure, however these pathways are likely to be overshadowed by the fish consumption pathway. Even in the case of subsistence sub-populations who may obtain a significant amount of their protein and/or calories from self-produced food stuffs, fish is expected to represent the dominant methyl-mercury source. In the case of ducks, although they may have methlymercury concentrations that match fish concentrations (although as the commentor noted, these studies have limitations), because ducks are not likely to consume upper-trophic level fish, their mercury levels are likely to be low compared with upper trophic level (predator) fish. For these reasons, EPA does not believe that significant uncertainty is introduced into either the primary benefits analysis, or consideration of distributional/equity issues through exclusion of these non-fish dietary pathways.

The RIA used measured mercury fish tissue data collected by both states (National Listing of Fish Advisories) and the EPA (National Fish Tissue Survey) and was not based on generalized data on mercury concentrations in commercial fish. While not providing complete coverage for all areas potentially fished by modeled populations including Native American populations such as the Chippewa, this fish tissue data set, does provide a reasonable degree of coverage for mercury fish tissue contamination in the context of conducting a benefits analysis. In the case of the Native American case study modeled for the RIA (the Chippewa), exposure

modeling was based on (a) fish tissue concentrations for waterbodies in the potential fishing activity zone of the Chippewa in Michigan and Minnesota and (b) fishing activity modeling that reflects reasonable assumptions regarding trip travel distances associated with fishing activity by the Chippewa. In other words, the benefits analysis was not based on generalized assumption regarding mercury contamination in commercial fish, but rather on measured mercury fish tissue concentrations measured in waterbodies likely accessed by this population.

Although EPA considers inclusion of the NFTS data extremely valuable in providing additional coverage for the study area, it is important to note that the majority of measured fish tissue concentrations were contributed by the NLFA and not by the NFTS. This fact partially addresses the commentor's concerns (i.e., the benefits analysis primarily reflects NLFA data with a smaller relative contribution from the NFTS dataset). EPA agrees with the commentor that NLFA data (when reflecting areas of increased fishing activity) would be preferable to randomly collected data for purposes of supporting a benefits analysis. However, given the patchy nature of the NLFA and the variety of sampling protocols used by different states in collecting data included in the NLFA, EPA considers the NFTS data to be very useful in filling in gaps in coverages and in providing a consistent randomly-sampled dataset to augment the purposively sampled data contained in the NLFA.

Comment:

One commenter (OAR-2002-0056-5423) presents an important source of information. Figure K1 shows the distribution of hair Hg values of 56 pregnant women sampled from 12 different native communities across Alaska. This 2002 survey by the State of Alaska Epidemiology Office confirms that on average Alaskan native pregnant women (with a mean hair Hg value of 0.6 ppm) consumed more fish than other average U.S. women (who have a mean hair Hg value of about 0.2 ppm based on the ongoing CDC's NHANES database). It is also clear from Figure K1 (see e-docket OAR-2002-0056-5423), based on the examination of 8 Aleutian mummies dated to about 550 years ago, that the native Alaskans had long been naturally exposed to significantly large levels of MeHg through fish and marine mammals in their traditional diets without any plausible "contamination" by power plant Hg emissions.

Exposure to MeHg in Alaska: Today Versus 550 Years Ago. Today's distribution with a mean of 0.6 ppm. Compare 0.6 ppm to the mean level of MeHg in 550-year old with one mummy with MeHg as high as 4.6 ppm. Aleutian mummies: 1.2 ppm (mean of 4 adults) 1.44 ppm (mean of 4 infants). State of Alaska Epidemiology Bulletin No. 29(December 11, 2002).

Regarding other native populations in Eastern North America, field records from Nunavik, Quebec (Figure K2, see e-docket OAR-2002-0056-5423) suggest that the prenatal exposure level of MeHg, lead and persistent organic pollutants (or POPs) in Inuit infants born between 1994 and 2001 has declined significantly. The authors of this new research paper concluded that "A significant reduction of lead and Hg concentrations was found, but there was no clear linear or exponential trend. The decreases observed could be explained by a decrease in food contamination, by changes in dietary habits, or, most likely by a combination of both.

Although questions remain as to the exact causes of decline, it is encouraging to observe such an improvement in prenatal exposure for this highly exposed population."

Concentrations of Hg, lead and persistent organic pollutants in umbilical cord blood of Inuit infants born in Nunavik, Quebec have been decreasing from 1994 to 2001 "A significant reduction of lead and Hg concentrations was found, but there was no clear linear or exponential trend. The decreases observed could be explained by a decrease in food contamination, by changes in dietary habits, or, most likely by a combination of both. Although questions remain as to the exact causes of decline, it is encouraging to observe such an improvement in prenatal exposure for this highly exposed population."

Equally important are explanations and cautions from this team of Laval University Medical Center researchers in an earlier publication (Dewailly et. al., 2001, Archives of Environmental Health, vol. 56, 350-357):

> "According to recommendations formulated by the World Health Organization (WHO), no more than 5 percent of individuals in a population should display a methylmercury concentration that exceeds 1000 nmol/L [or converted to 200 µg/L MeHg in blood]. Concentrations of total mercury noted in present study did not exceed 560 nmol/L [112 µg/L]. WHO issued more stringent recommendations for pregnant women, stating that not more than 5 percent of this subgroup should exhibit methylmercury concentration above 400 nmol/L [80 µg/L]. In our survey, no women of childbearing age exhibited concentrations of this magnitude. Recent data from Faroe Island suggest that the neurologic status of children can be affected by low-level prenatal exposure to mercury. There are, however, major differences between the diet of Faroese and the diet of Inuits, and care must be exerted before one concludes that Inuit children are at risk. [I]n view of the high selenium intake [in the diets of the Inuit population from consumption of mattak (beluga whale skin) which is about 2.4 times higher than that measured in the Farose], which may counteract methylmercury-induced toxicity, local public health authorities did not recommend reducing seafood consumption."

If EPA has serious concerns for native populations, it should focus on the fact that instead of advancing health and safety for these peoples, Hg warnings are already causing harm. John Middaugh, State Epidemiologist of Alaska, recently warned FDA:

> "Advisories based upon risk assessment without consideration of well-established public health benefits of fish consumption have great potential to harm public health if reductions in fish consumption occur."

Middaugh reported that many native Alaskan communities abandoned traditional fish diets since the FDA's 2001 Hg advisory, with a subsequent increase in diabetes, heart disease, and vitamin A and D deficiencies.

Response:

As described in other responses, the Agency has high confidence in the RfD for methylmercury. EPA encourages the public to vary the species and sources of fish in order to obtain the benefits of fish consumption while avoiding elevated exposures to methylmercury. The fish advisory developed jointly with the Food and Drug Administration emphasizes the benefits of including fish in a healthy diet while informing the public on ways to reduce methylmercury exposure (http://www.epa.gov/waterscience/fishadvice/advice.html).

Comment:

One commenter (OAR-2002-0056-5423) supports EPA's intention to properly apply information from the ongoing CDC's NHANES database (which some at EPA have not done), but must stress that no women (Figure L1, see e-docket OAR-2002-0056-5423) or children (Figure L2, see e-docket OAR-2002-0056-5423) in the current NHANES survey are actually harmed by the levels of Hg in their blood from fish consumption.

The commenter will delay comments on the ultra-conservative nature of the MeHg RfD value set by EPA, as shown in Figures L1 and L2, to comment (O) (see e-docket OAR-2002-0056-5423). The commenter will also confirm in comment (O) that EPA's MeHg RfD was derived from the Faroe Islands Children Study that was plagued by contaminants like PCBs and DDT through consumption of pilot whale products and hence is widely recognized in professional circles as incompatible with or irrelevant to the U.S. consumption profile of a wide variety of fish (i.e., excluding whale products).

Response:

In deriving the reference dose for methylmercury, EPA relied on an integrated analysis involving three studies. These longitudinal, developmental studies were conducted in the Seychelles Islands, the Faroe Islands, and New Zealand. The Seychelles study yielded scant evidence of impairment related to in utero methylmercury exposure, whereas the other two studies found dose-related effects on a number of neuropsychological endpoints. In the assessment developed for the RfD, emphasis is placed on the results of the Faroe Islands study, the larger of the two studies that identified methylmercury-related developmental neurotoxicity. Supporting evidence from the New Zealand study provides assurance that choosing this focus is the appropriate strategy for protecting public health. Conclusions from the National Research Council review of methylmercury support this use of the Faroes Island study and disagree with the suggestion of a role for PCBs in the neurological effects observed (NRC. 2000. Toxicological Effects of Methylmercury. National Academy Press.), saying that

> *"The committee concludes that there do not appear to be any serious flaws in the design and conduct of the Seychelles Islands, Faroe Islands, and New Zealand studies that would preclude their use in a risk assessment."*

The Agency's derivation of the RfD also followed the National Research Council recommendation for an overall composite uncertainty factor of no less than 10.

In summary, the Agency's overall confidence in this RfD assessment is high. Three high-quality epidemiological studies published since the last derivation of the oral RfD in 1995, have been included in the analysis. Two of the studies (Faroe Islands, New Zealand) reported effects on a number of neuropsychological endpoints, whereas the third (Seychelles Islands) reported no effects related to in utero exposure to methylmercury. Benchmark dose analysis of a number of endpoints from both the New Zealand and Faroe Islands study converged on an RfD of 0.1 μg/kg-day, as did the integrative analysis combining all three studies. Although there was coexposure to PCBs in the Faroe Islands study, statistical analysis indicated that the effects of PCBs and methylmercury were independent. Moreover, benchmark dose analysis of the endpoints that were significantly associated with methylmercury yielded RfDs that were approximately the same when corrected for PCBs. The same was true when the analysis was or based on the subset of the cohort in the lowest tertile with respect to PCB levels, as compared with the full cohort. These findings provide further evidence that the identified effects are in fact the result of methylmercury exposure.

Comment:

The commenter (OAR-2002-0056-5460) stated that with regard to step four of the proposed revised benefits assessment methodology, EPA has not adequately explained how it intends to supplement data from the National Listing of Fish Advisories with data from the National Study of Chemical Residues in Lake Fish Tissue, let alone why such supplementation is necessary. The commenter added that EPA has likewise failed to explain why it is appropriate to develop, in the context of the CAMR, national estimates of the mean concentrations of 268 chemicals in fish tissue from lakes and reservoirs across the U.S. The commenter stated that EPA should not use national estimates to underestimate Hg concentrations, or Hg exposure, in any particular region or area of the country.

Response:

The benefits analysis completed for the RIA is not intended to model local-scale changes in fish tissue concentrations and exposures in support of site-specific risk analysis. Instead, modeling conducted for the RIA is intended to capture generalized regional changes in methlmercury exposure resulting from reductions in power plant mercury emissions in order to support a national-scale benefits assessment focusing on the 37-State eastern US study area. For additional details on the benefits analysis modeling framework see Section 10 of the RIA.

Although EPA is not conducting local-scale modeling of mercury fish tissue concentration changes resulting from decreased mercury deposition, the modeling framework used in this RIA is believed to have sufficient precision to generate reasonably accurate benefits estimates. Specifically, 36km^2 CMAQ grid cell air modeling results are used to project deposition changes over individual fish tissue sampling locations for purposes of predicting changes in fish tissue concentrations related to emissions reductions from power plants. In addition, recreational anglers and additional potential high-exposure populations (e.g., high-end consumers and Chippewa) are modeled using relatively spatially-differentiated behavioral and exposure models which consider both the distribution of fishers across the study area (at the

US Census block group, or 8-digit HUC level) and the potential behavior of fishers in accessing different areas or zones for fishing. This modeling framework is believed to provide sufficient spatial resolution in characterizing regional patterns of population-level exposure to mercury through fishing activity (and consumption) to support the benefits analysis. For additional detail on the benefits modeling framework, see Section 10 of the RIA.

Although EPA considers inclusion of the NFTS data extremely valuable in providing additional coverage for the study area, it is important to note that the majority of measured fish tissue concentrations were contributed by the NLFA and not by the NFTS. This fact partially addresses the commentor's concerns (i.e., the benefits analysis primarily reflects NLFA data with a smaller relative contribution from the NFTS dataset). EPA agrees with the commentor that NLFA data (when reflecting areas of increased fishing activity) would be preferable to randomly collected data for purposes of supporting a benefits analysis. However, given the patchy nature of the NLFA and the variety of sampling protocols used by different states in collecting data included in the NLFA, EPA considers the NFTS data to be very useful in filling in gaps in coverages and in providing a consistent randomly-sampled dataset to augment the purposively sampled data contained in the NLFA.

The procedure used to generate a single standardized fish tissue dataset for use in supporting the benefits analysis using data from both the NLFA and NFTS datasets is described in the CAMR RIA. Regarding the rationale for combining the two datasets, EPA believes that the NLFA provides a large number of fish tissue samples with some bias for areas likely fished (which is advantageous in supporting the benefits analysis), while the NFTS, with its statistically random sampling strategy, provides consistent spatial coverage for waterbodies across the study area and in that way, can fill in gaps left by the NLFA.

Comment:

One commenter (OAR-2002-0056-5497) stated that the development of an assessment protocol that melds regional fish consumption patterns with the distribution of MeHg concentrations in fish is an immensely challenging and complex undertaking. Existing fish tissue samples must be normalized to account for differences in fish age, length, etc. Fish consumption data must be developed at the regional level to reflect differences in the types of species consumed, the source of those fish (including whether they come from highly productive waterbodies or not)" and the amount of fish consumed. The commenter does not see how the analyses described in Step 4 could be completed, in any scientifically valid way, by March 15, 2005.

EPA's request for comments on the incorporation of the National Listing of Fish Advisories' (NLF A) and National Fish Tissue Study's (NFTS) fish tissue data into the National Descriptive Model of Mercury and Fish Tissue (NDMMFT) suffers from EPA's failure to make the pertinent material available in the docket. EPA's promise to place these materials in the docket "when available" makes it difficult, if not impossible, to respond to EPA's questions in a detailed manner. EPA should not use NDMMFT in a benefits analysis without further public comment.

As for the fish consumption rates incorporated into EPA's MeHg fish tissue criterion, they are conservative. The default consumption rate of 17.5 grams/day is based on a value representing the 90th percentile of the value for freshwater and estuarine fish from a 1995-96 study conducted by the Department of Agriculture. Default fish intake rates for recreational and subsistence fishers of 17.5 grams/day and 142.4 grams/day respectively are based on values representative of the 90th and 99th percentiles of the general population. The fish tissue criterion is designed to be highly protective, not to accurately predict fish consumption rates in a way that would be realistic for a benefits analysis.

Response:

EPA has implemented a methodology for the RIA that accomplishes most of the technical tasks noted by the commenter. For the RIA, EPA has used the NDMMFT statistical model to effective standardize the measured fish tissue concentrations with regard to size (length) and species. This produces a standardized (diet relevant) set of fish species and lengths for use in the benefits analysis and avoids the inclusion of non-diet relevant sizes/species in exposure modeling. Regarding fish consumption rates, EPA acknowledges that regional differences are likely to exist both for recreational anglers as well as high-consumption (subsistence) populations. However, with regard to recreational anglers, EPA could not identify regional- or local-scale studies in the literature with sufficient collective coverage to allow comprehensive modeling of the 37-State study area without leaving large gaps in geographic coverage (i.e., individual studies covering smaller geographic areas or watersheds were identified, but they could not be combined to provide a cohesive coverage for the study area). Ultimately, the consumption rates for the recreational angler that were used in the RIA were obtained from peer-reviewed studies and are representative of general trends in behavior for this group. For special populations (i.e., the Chippewa and Hmong), consumption rates based on peer-reviewed studies focusing on these specific ethnic groups were used. The RIA contains an expanded description of our application of the NDMMF. More information about the model itself can be found at http://pubs.water.usgs.gov/sir20045199/.

5. Step 5: Assessing the relationship between reductions in human exposure and improvements in public health. EPA sought comment on all aspects of its proposed revised methodology for estimating the relationship between reductions in methylmercury exposure and improvements in health. In particular, EPA sought comment on: (1) the focus on neurodevelopment health of children; (2) the selection of IQ as an endpoint for quantification of neurodevelopmental effects and whether it is an appropriate endpoint for benefits analysis; (3) whether other neurodevelopmental effects can be quantified and are amendable to economic valuation; (4) whether, and if so how, data from the Faroe Islands, New Zealand, and Seychelles Islands studies can be integrated for the benefits analysis; the choice of the K=1 model for estimating the relationship between exposure and IQ and practical alternatives to that approach; and the appropriateness of using a linear dose-response model given the EPA's reference dose, which assumes a threshold does below which there is not likely to be an appreciable risk of deleterious effects

during a lifetime.

Comment:

The commenter (OAR-2002-0056-5542) has historically been united in its advocacy that federal regulatory agencies such as the EPA must use sound science and risk prioritization. The commenter has supported "scientifically sound risk analysis; risk-based prioritization; benefit-cost analysis; flexible, efficient, cost-effective risk management; and public participation in all phases of the process." The commenters stated that their policy also expressly supports a conclusion made by EPA in its document, "Reducing Risk: Setting Priorities and Strategies for Environmental Protection, 2 September 1990," which states:

> There are heavy costs involved if society fails to set environmental priorities based on risk. If finite resources are expended on lower-priority problems, at the expense of higher-priority risks, then society will face needlessly high risks. If the priorities are established based on the greatest opportunities to reduce risk, total risk will be reduced in a more efficient way, lessening threats to both public health and local and global ecosystems.

The commenter was concerned that the EPA is chasing a Hg emissions reduction goal that is a low-priority problem that represents little or no risk, but would nevertheless be squandering finite economic resources that are needed for economic growth and for meeting higher priority risks. Since the EPA's Hg decisions could have the effect of dramatically reducing coal use in the U.S., generators trying to fulfill the nation's growing need for electricity would then be forced from abundant coal to either scarce natural gas or future nuclear power.

The commenter noted that the current EPA has access to almost a decade more research regarding both the real science of public health exposure to U.S. power plant emissions of elemental Hg and to the net public health benefits of eating fish, the primary source of Hg accumulation in the body. The commenter believed that the EPA must correct the refuted science that was the foundation of the Agency's reference dose, and therefore the foundation of the agency's proposed Hg rule.

Under the sound science category, the commenter believed the central issues for the agency are whether any level of MeHg consumption by humans was acceptable; and whether reducing elemental Hg emissions from U.S. power plants will have any measurable impact on the MeHg levels in fish broadly consumed by the American public. Many epidemiological studies have been undertaken since the EPA first picked its reference dose level that show almost uniformly that some levels of MeHg in humans are acceptable. Further, natural levels of MeHg, as well as the deposition of elemental Hg from sources outside the U.S., ensure that even closing U.S. coal-fired power plants will not affect the quantities of MeHg in fish that the U.S. population ingests.

As carefully documented in the comments filed by the Utility Air Regulatory Group

(URAG) on June 29, 2004, the EPA made a number of serious procedural mistakes and deviations from its customary and or appropriate processes in order to conclude that Hg emissions from coal-fired power plants were adversely affecting public health. The nation is facing many real risks of terrorism and natural events, such as infectious diseases, hurricanes, volcanoes or tsunamis. Manufacturers in particular are facing intense and sometimes unfair international competition and escalating structural costs at home from an out-of-control legal system, skyrocketing pensions and health benefit costs, high corporate taxation, high energy costs and over-zealous regulation. The nation, and certainly the manufacturing sector (which still accounts for 13 percent of the U.S. economy), can ill afford expensive regulations promulgated in order to chase minor or negative net risks to public health.

The EPA itself has stated that there is a reference dose level of MeHg in the body "below which there is no danger to human health." Other entities, including the World Health Organization, the U.S. Federal Food and Drug Administration (FDA), the Agency for Toxic Substances and Disease Registry (ATSDR), Health Canada (Canada's FDA) and the U.K. Committee on Toxicity in Chemicals in Food have all picked levels at which MeHg in the body is not harmful, and the threshold levels set by each organization are well above the EPA's recommended level. In other words, the EPA has not only picked an unnecessarily low level of human exposure compared to five other U.S. and international organizations, but it now appears that the agency is suggesting that there is no dose of MeHg that is safe. If that is what the EPA is now concluding, it is not only contrary to all existing scientific evidence, including the on-going analysis of the value of selenium in countering MeHg exposure, it constitutes a tragic application of the easily-abused precautionary principle. Moreover, how is the EPA proposing to measure the positive health impact of the Hg reductions it is proposing? If the EPA discovers that there is no measurable positive impact from its new rules, would the EPA then rescind its regulations?

Only by declaring that there is no safe dose of MeHg can the EPA justify reducing emissions from U.S. power plants. This is because there is ample evidence to show that elemental Hg emissions from U.S. power plants are a very small percentage of the elemental Hg falling onto U.S. soil and waters. Further, there is ample evidence, submitted in detailed comments by the Center for Science and Public Policy and others to this NODA, that MeHg levels in fish and humans who eat them have remained constant since before the industrial revolution and subsequent abundant coal use. In defending its position that reducing Hg emissions from power plants will result in lower MeHg levels in fish, the EPA has given some weight to the Florida Mercury Report of Nov. 6, 2002, regarding MeHg changes in fish in the Everglades during the 1990's after Hg emission controls were placed on waste incinerators in the area. However, the assumptions of this study have been challenged. (See "A Framework for Assessing the Cost-Effectiveness of Electric Power Sector Mercury Control Policies", PERI, May 2003. [In a press release issued on November 13, 2003, PERI observed that the Everglades study is flawed in several material ways, including by not recognizing substantial differences between incinerator and power plant emissions.)

If the EPA determines that there is no safe Hg level, then the agency must either order a

ban on all fish or eliminate all sources–natural and anthropogenic–of elemental Hg into the environment. Of course, it is impossible to eliminate Hg that is transported in the air from Asia, that naturally exists in the soil and oceans, and that is emitted from forest fires and volcanoes. Merely regulating one very small part of the Hg cycle U.S. power plants–would do little if anything to protect human health from exposure to MeHg from fish. Accordingly, a ban on eating fish would be the only logical outcome of a policy driven by a belief that there is no safe Hg level.

The EPA has an opportunity to correct the health-science record before the agency puts its full reputation as the protector of public health behind staff opinions that are now based on refuted, discredited, decade-old studies, including the Faroe Island study. It is now clear that the Faroe Island study was discredited after the original EPA analysis and after the National Research Council study of 2000, both of which the EPA is currently relying on to justify its proposed reference dose.

The commenter either supported the fishing industry or were in the fish processing industry. These companies are severely affected by any scare mongering that frightens Americans away from eating fish as part of their diet. For a detailed analysis of the net harm of scaring people away from eating fish, including the loss of net pregnancy and net cardiovascular benefits, see the comments being submitted on this NODA by the Center for Science and Public Policy. The Center for Science and Public Policy also provides analysis of the deficiencies and failings of several studies that find negative cardiovascular effects from consuming MeHg from fish. The EPA also should recognize that The Institute of Medicine is going to do a two-year study of the benefits of fish consumption, which could embarrass any EPA actions that have resulted in driving people away from fish consumption for no measurable health benefit.

The commenter added that any EPA analysis must consider other risks to public health that occur when electricity and natural gas prices skyrocket as a consequence of excessive EPA regulation of coal-fired electric generation. Clearly, additional costs on manufactures will continue to erode the manufacturing employment base in this country as they struggle to compete with low-cost foreign manufacturers. However, not only are manufacturing jobs at risk–and the higher compensation, better health care and pension plans that manufacturing workers enjoy compared to the rest of the economy–but so are risks associated with a lower tax bases that is the result of having a weak manufacturing sector, which would lead to lower public services, including health clinics. A weak manufacturing sector and high electricity costs will sap the investment markets upon which millions of current and potential retirees depend. Finally, dramatically increasing the costs of electricity and natural gas prices paid by homeowners must be recognized as harming many economically disadvantaged people, who have the least capacity to absorb these additional costs.

Thus, the EPA's actions to regulate Hg emissions have the significant - and so far unaccounted for by the EPA - potential for harming public health that must be weighed against the minuscule benefits of regulating elemental Hg emissions from U.S. coal-based power plants.

Response:

Please see the RIA as well as the Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units and the Removal of Coal- and Oil-fired Electric Utility Steam Generating Units from the Section 112(c) List for a discussion of the Agency's rationale for not proceeding under Section 112 Notice and in the Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls in the docket.

Comment:

One commenter (OAR-2002-0056-5556) noted that the EPA need not limit its benefits analysis to any single quantifiable health benefit but rather should consider all pertinent anticipated benefits to human health. It may be especially important to include a discussion on the benefits to adult cardiovascular health as this effect has been correlated with MeHg exposures at or below levels associated with neurodevelopmental effects (Toxicological Effects of Methylmercury, National Academy of Sciences, 2003). This commenter stated that it is also important to include any expected improvements in water quality and subsequent reductions of MeHg in fish tissue, realizing that a reduction in Hg emissions of at least 75 percent may be required before measurable environmental impacts can be detected.

Response:

EPA recognizes that research is ongoing in a number of areas related to both mortality and morbidity in relation to methylmercury exposure. However, at the time of this regulation, existing peer-reviewed evidence was not considered sufficiently conclusive to include these additional health endpoints in the primary benefits analysis and EPA has focused on reductions in IQ resulting from prenatal exposure in estimating health-related benefits. See Appendix B for a detailed discussion of the current status of research involving the mortality endpoint for methylmercury exposure.

Comment:

One commenter (OAR-2002-0056-5471) referenced comments on the Proposed Rule that supports the control of Hg from coal-fired EUSGUs through a cap-and-trade program. However, for the ultimate rule to establish a regulatory program that reflects a reasonable estimate of benefits from Hg emission reductions, this commenter believes that EPA must assign to EUSGU Hg emissions only those health risks that can be traced to those emissions.

In the preamble to the Proposed Rule, the Agency claimed that substantial benefits would result from the proposed CAMR. But the claimed benefits are based almost entirely on the value of estimated health benefits from the decline in ambient $PM_{2.5}$ caused by the SO_2 and NOx reductions resulting from the control measures required to reduce Hg emissions (primarily SO_2

scrubbers and selective catalytic reduction (SCR)). Because the Proposed Rule relied almost exclusively on these co-benefits of the proposed regulatory control of Hg, this commenter stated that no health benefits were directly associated with reductions in Hg emissions. The Agency's intention in the NODA, at least in part, appears to be to develop a methodology to better quantify benefits attributable to the proposed CAMR by isolating the benefits of Hg emissions reductions from those benefits associated with SO_2 and NOx emission reductions. While this commenter supports the Agency's undertaking of the additional analysis, EPA's proposed approach to assessing the benefits of Hg emissions reductions creates a danger of overestimation of those benefits.

Response:

EPA has developed a benefits analysis methodology for this RIA that is designed to provide unbiased estimates of health-related benefits resulting from regulatory options considered under CAMR. In keeping with convention, efforts have been made to use peer-reviewed methods and data sets when available and to avoid introducing conservative assumptions at all stages in the benefits modeling process. EPA's emphasis on representativeness has meant that a number of health endpoints, that may ultimately be supported by research findings (e.g., cardiovascular-related mortality and immunologic-related morbidity), have been excluded from the primary analysis in order to include only those endpoints in the formal benefits analysis for which there is strong peer-reviewed support. For additional details on the modeling framework including all key assumptions and input datasets, please review Chapter 10 in the RIA.

Comment:

One commenter (OAR-2002-0056-5471) noted that in the NODA, EPA requests general comments on analytical approaches to translating estimates of reductions in Hg emissions from EUSGUs into approximate health outcomes in humans. It has been suggested that one guide for this analysis is the Agency's regulation of lead. In the late 1970s, EPA initiated a successful program designed to eliminate all lead emissions into the environment primarily through the phase-out of leaded gasoline. Since airborne lead emissions are linked to blood lead levels in children and related neurological impacts, it may appear reasonable to utilize the lead elimination model for dealing with Hg.

However, this commenter believes there are significant differences between the nature of lead emissions and EUSGU Hg emissions and the health benefits reasonably associated with reducing those emissions. If these differences are not taken into account, the commenter believes that blindly making assumptions for Hg emissions reductions based on the Agency's experience with lead will cause EPA to overestimate the benefits of Hg emissions reductions. First, virtually all airborne lead is attributed to anthropogenic sources while a large percentage of airborne Hg (greater than 50 percent) is due to natural sources. Thus, while the Agency acted reasonably in targeting all lead emissions, it is impossible to eliminate all airborne Hg emissions. Second, lead emissions and ambient lead concentrations are primarily associated with urban

areas while Hg emissions and ambient Hg concentration are widespread on a global scale. Third, while there appears to be no lower limit for neurological impacts for lead blood levels, Hg blood levels have a clear threshold below which there are no neurological impacts. Fourth, while neurological impacts were clearly shown at blood lead levels present in children in U.S. urban areas in the 1970s, no such neurological impacts have been noted or documented at Hg blood levels currently found in child-bearing age women or children in the U.S.

Comment:

One commenter (OAR-2002-0056-5471) noted that in explaining Step 5 of its revised benefits analysis, EPA seeks comment on its proposed use of three studies, including a study from the Faroe Islands, to estimate the relationship between reductions in MeHg exposure and improvements in health and its proposed use of intelligence quotient (IQ) decrements associated with prenatal MeHg exposure to quantify and value the health benefits of reduced exposure to MeHg.

EPA has selected a reference dose (RID) for Hg in maternal blood (5.8 ppb) that serves as a de-facto threshold. This number, which is 10 times below the threshold number developed from the Faroe Islands study and 14 times lower than the World Health Organization's level of concern, is very conservative. This commenter believes that if an unrealistically low threshold for Hg blood levels were used to estimate benefits, reductions in blood levels between the true threshold and the unrealistically low one would create the appearance of a benefit where there is none.

The commenter stated that the danger of using the RID as the benchmark for assuming benefits is revealed by EPA's proposal to develop a relationship between Hg emissions and general population IQ. There is no evidence of IQ impact at blood Hg levels greater than the RID but below the Faroe Island threshold level. Yet, if this relationship were then coupled with an imputed value for increased IQ for the general population, large estimated benefits could be generated that would not exist. Likewise, if EPA's proposed assumption of a linear response between blood Hg levels and IQ would lead to an imputed benefit for reducing blood Hg below the threshold level, the Agency would be creating benefits that do not exist.

While the commenter does not support all the findings of the Faroe Islands study, the study provides a minimum threshold for blood Hg levels. This commenter recommends that the Agency use at least the threshold level established in that study (if not a higher one, such as the WHO level of concern), and not the RID, as the benchmark for measuring health benefits.

Response:

Please see Chapters 10 and 11 of the RIA for a discussion of the CAMR benefits.

Comment:

One commenter (OAR-2002-0056-5476) commented on Step 5 of the NODA addressing cost/benefit analyses and how reduction will improve human health. The commenter finds that EPA's benefits analysis does nothing to address the importance of fishing as a cultural practice. There is no way to place a dollar amount on the benefit to spiritual well-being as a result of practicing a centuries-old tradition and passing it on to our children. In a more concrete measurement, EPA does nothing to address replacing a subsistence food source that provides a significant amount of nutrition for our Band members. In making a local, easily obtainable food source inedible due to poisoning, EPA should calculate the costs that will be incurred in cleaning up these toxins to improve the health and physical well-being of the people and the health of the environment for today's and future generations. The commenter was also unaware of any attempts EPA has made to quantify the costs of the learning and educational problems that exposed children may experience. For example, the loss in lifetime earnings resulting from retardation of mental aptitude in the generalized population as a result of Hg poisoning has been estimated at $2.3 billion per year. By refusing to set adequate MACT standards, EPA is shifting this economic burden onto the heads of indigenous people and their communities as a whole. Another error in the EPA's cost/benefit analysis comes from the projection of $15 billion in savings due to health-related benefits from its proposed rule when forecasted against the do nothing option. These are simply health benefits that accrue from EPA's very substandard proposal. The commenter believes that if the more stringent MACT standard were set in place, additional billions of dollars could be saved.

This commenter believes that EPA has also failed to assess tourism-related impacts. Tourism in $9.8 billion annually in Minnesota alone. Of this total, sport enthusiasts spend $1.58 billion, or 16 percent. Locally, Lake Mille Lacs universally recognized as a premier trophy fishing lake and its Lake-related tourism adds an estimated $150 million into the local economy annually. Although it is unknown to what level fish advisories impact these number, fishing and tourism bring in income that the State of Minnesota cannot afford to lose. The other Great Lakes states of Wisconsin, Michigan, Illinois, Indiana, and Ohio face similar situations. Together, these States, along with Minnesota, attract 7.8 million anglers annually who spend $5 billion in fishing-related dollars. Although these are not directly health-related issues, they certainly need to be addressed in EPA's economic considerations.

The commenter also takes issue with the modeling performed in the analysis. The commenter does not believe the science of modeling is at a state where it can accurately be used for Hg due to the lack of understanding about dry deposition. Currently among many ambient air-monitoring personnel, there is a strong opinion that there are too few dry deposition monitors in the North American continent and barely adequate network of wet deposition monitors in the eastern half of the U.S., with very little of either monitors existing on Anishinaabewaki (Indian Country) so it is very hard to say how much wet or dry deposition of Hg is occurring in these areas. Based on this concern, the commenter believes it is not in the Band's interest to propose a cap and trade program relying on the results of EPA's models. In turn, the commenter asks the EPA to uphold its Trust responsibility obligations by erring on the side of caution rather than be wrong in such an important matter. To account for the lack of confidence in the models, EPA should abandon its idea of cap-and-trade and cleave to a MACT standard.

The commenter believes that the National Emissions Inventories used in EPA's analysis probably underestimated the amount of Hg emitted from some sources, especially in the western and central regions of the U.S., such as miscellaneous product disposal. EPA has used the best information it has available, but it should leave a margin of safety to account for inaccuracies.

The commenter believes there is a MACT calculation problem. The EPA seems to have followed a methodology recommended by a utility trade group, using a short-term worst-case analysis to develop a long-term average standard. This method used only the 2.5 percent worst emissions from relevant sources, ignoring the 97.5 percent best emission reductions.

The commenter would like to reference the excellent comment letter by the Forest County Potawatomi Community (FCPC) to EPA on the Mercury Utility Rule (US EPA Document ID No. OAR-2002-0056-2173, April 27, 2004). The experts retained by the FCPC stated in attachments to that letter why EPA's proposed MACT standards are unacceptable and why EPA improperly failed to consider alternate methods of removal, such as activated carbon injection. The commenter is unable to make specific comments on these issues as time is running short. The commenter also believes that it cannot add anything to the discussion that has not already been said in the FCPC letter.

In studying Table 1 of the Notice of Data Availability, it appears that it really is not much more expensive to control emissions of 7.5 tons per year rather than of 15 tons per year. A two-phase cap of 15 tons is projected to cost $3.3 billion by 2010 and $6.7 billion by 2020. But a two-phase cap of 7.5 tons is expected to cost $4.6 billion by 2010 and $7.1 billion by 2020. The difference by 2020 is only 6 percent! Even with all of EPA's incomplete assumptions that lead to faulty calculations and failure to carry out a proper MACT determination, it only makes a 6 percent difference in cost.

Though most of the Band members are oblivious to any of EPA's calculations or rule-making, among those of us in Tribal Government who are entrusted and statutally obligated to protect the health of our Band members and the health of the natural resources available to the Band members, or to our Band members who actively seek to information, it would be hard to over-state the level of utter disbelief expressed across Anishinaabewaki over the way EPA has handled this rule-making.

Response:

EPA has used a cost-of-illness function based on lost earnings resulting from methylmercury exposure as the basis for its primary benefits estimate in the RIA (i.e., prenatal methylmercury exposure through maternal consumption producing IQ decrements in children which translate into lost earnings later in life). This valuation function, which is based on the approach used in past EPA regulations concerning lead exposure, also considers the impact of lowered IQ on years of education achieved. EPA acknowledges that because this function is based on cost-of-illness and not willingness-to-pay (WTP), it likely represents a lower bound for valuation of the IQ decrements and that a more comprehensive WTP-based function would

capture other factors such as those listed by the commentor above. Note, EPA did not use a WTP-based function in the benefits analysis because peer-reviewed literature does not support derivation of such a function at this time.

Comment:

One commenter (OAR-2002-0056-5517) notes that the NODA fails to provide a scientifically sound reason as to why EPA adds a factor-of-ten safety factor in calculating what is an acceptable daily intake of MeHg from eating fish. Adding such a safety factor is usually done to account for how sensitive populations, such as children, who are believed to be more sensitive to MeHg than adults, differ in response to the general population.

This commenter points out that the reason the additional safety factor, as used by EPA, is questionable is that the available studies of the health effects of MeHg exposures focus both on healthy and sensitive subpopulations inclusively, thus their particular susceptibilities are already accounted for, obviating the need for any added safety factor. EPA has provided no information in this NODA that would justify the inclusion of the factor-of-ten safety factor used by the agency; as such its use is clearly arbitrary and capricious. Moreover, there is no explicit statutory authority in the Clean Air Act that mandates the use of such a safety factor.

In their comments to EPA concerning the agency's proposed rule to control emissions of Hg from coal-fired power plants, other national trade associations have also addressed the questionable safety factor used by EPA in establishing what is an acceptable daily intake of MeHg from eating fish. These organizations also find that the use of the factor-of-ten safety factor is not justified. The commenter believes that its observations have merit and must be given careful consideration.

Response:

In deriving the reference dose for methylmercury, EPA relied on an integrated analysis involving three studies. These longitudinal, developmental studies were conducted in the Seychelles Islands, the Faroe Islands, and New Zealand. The Seychelles study yielded scant evidence of impairment related to in utero methylmercury exposure, whereas the other two studies found dose-related effects on a number of neuropsychological endpoints. In the assessment developed for the RfD, emphasis is placed on the results of the Faroe Islands study, the larger of the two studies that identified methylmercury-related developmental neurotoxicity. Supporting evidence from the New Zealand study provides assurance that choosing this focus is the appropriate strategy for protecting public health. Conclusions from the National Research Council review of methylmercury support this use of the Faroes Island study and disagree with the suggestion of a role for PCBs in the neurological effects observed (NRC. 2000. Toxicological Effects of Methylmercury. National Academy Press.), saying that

> *"The committee concludes that there do not appear to be any serious flaws in the design and conduct of the Seychelles Islands, Faroe Islands, and New Zealand studies that*

would preclude their use in a risk assessment."

The Agency's derivation of the RfD also followed the National Research Council recommendation for an overall composite uncertainty factor of no less than 10.

In summary, the Agency's overall confidence in this RfD assessment is high. Three high-quality epidemiological studies published since the last derivation of the oral RfD in 1995, have been included in the analysis. Two of the studies (Faroe Islands, New Zealand) reported effects on a number of neuropsychological endpoints, whereas the third (Seychelles Islands) reported no effects related to in utero exposure to methylmercury. Benchmark dose analysis of a number of endpoints from both the New Zealand and Faroe Islands study converged on an RfD of 0.1 μg/kg-day, as did the integrative analysis combining all three studies. Although there was coexposure to PCBs in the Faroe Islands study, statistical analysis indicated that the effects of PCBs and methylmercury were independent. Moreover, benchmark dose analysis of the endpoints that were significantly associated with methylmercury yielded RfDs that were approximately the same when corrected for PCBs. The same was true when the analysis was or based on the subset of the cohort in the lowest tertile with respect to PCB levels, as compared with the full cohort. These findings provide further evidence that the identified effects are in fact the result of methylmercury exposure.

Comment:

One commenter (OAR-2002-0056-5517) reports that it recently received an e-mail communication from Professor Gary Myers of Rochester University who leads the child development study of prenatal MeHg exposure from ocean fish consumption in the Seychelles Islands. His e-mail message concerns EPA's stated intention outlined in the NODA to analyze whether data from the various major MeHg exposure-effects studies, such as those of the Seychelles and Faroe Islanders, can be integrated. Dr. Myers observes, "I do not think there is any way to compare the two [Seychelles and Faroe Island] studies regarding exposure. They are simply different." In view of this communication, the commenter suggests that EPA confer further with Dr. Myers on this matter to clarify the specifics of his expressed concern.

Response:

Please see Chapter 9 of the RIA for a discussion of the derivation of a dose-response function using both the Seychelles and Faroes data.

Comment:

One commenter (OAR-2002-0056-5447) stated that EPA's NODA poses a number of questions related to modeling runs that have been performed to simulate electric system operation and decision making to predict how utilities would comply with EPA's two proposed regulatory options. 69 Fed. Reg. 69866-69872. EPA states that modeling predictions of how electric generation would shift in response to the Hg rule is relevant because EPA is required to

examine “cost, nonair quality health and environmental impacts, and energy requirements” under both Clean Air Act (CAA) § 111 and 112(d). 69 Fed. Reg. 69866

The commenter also noted that EPA also requests comments on its proposed revisions to its benefits assessment under EO12866. 69 Fed. Reg. 69,872. EO12866 states that “agencies should assess all costs and benefits of available regulatory alternatives.” EO12866, Section 1. Costs and benefits must be considered on a “net” basis, meaning both positive and negative public health effects of a regulation must be considered together. Id. The fact that it is difficult to quantify certain costs and benefits does not mean these costs and benefits may be ignored. Under EO12866, “[c]osts and benefits shall be understood to include both quantifiable measures (to the fullest extent that these can be usefully estimated) and qualitative measures of costs and benefits that are difficult to quantify, but nevertheless essential to consider.” Id. EPA’s analysis of the “cost [and] nonair quality health and environmental impacts” and its EO12866 benefits assessment are defective because they fail to consider significant societal costs associated with unduly-stringent Hg regulations. Indeed, a number of outcomes forecast by the modeling performed in this docket (e.g., plants shutting down) would cause significant economic and human health impacts that are overlooked in EPA’s analysis. If coal plants are modeled to shut down (e.g., Cinergy’s model of “Stringent MACT Plus CAIR,” 69 Fed. Reg. 69868, col. 3) or reduce capacity factors, these shut downs will cause the economic impacts of increased gas and electricity prices. These higher prices will, in turn, cause higher costs in the manufacturing sector, loss of jobs, and the loss of energy security. According to a recent study, “replacement of U.S. coal-fueled power could impact household income by an estimated $125-$225 billion in 2010,”

In addition, forcing a shift in the nation’s fuel supply from coal to natural gas will result in significant increased risks to public health. Depending on the models used, removing coal from America’s energy mix would directly result in anywhere from 7,000-51,000 premature adult deaths per year. However, severe mortality impacts would result even if EPA’s regulations do not cause a complete shut down of coal-fueled electricity, but only cause some shift from low-cost coal generation to higher priced gas generation. One model shows that an aggregate reduction in household income of $8.9 million induces one additional adult death. These deaths would fall disproportionately on lower-income households.

Modeling outcomes that predict some coal-fueled units will be shut down or run at decreased capacity must incorporate all potential impacts of such shut-downs or decreases in capacity when assessing the costs of the regulation. At this point, EPA’s forecast modeling and benefit analysis does not consider the societal impacts of regulations that would cause power plants to shut down or run at decreased capacity. Until such analysis is provided, EPA has not met its obligation under EO12866 to assess all the costs and benefits of its Hg regulation and to do so on a net basis. For the same reason, EPA will have failed to fully assess the “cost, nonair quality health and environmental impacts” of the regulation under CAA §111 and 112(d).

Response:

The comment raises issues under the general broad issue of correctly differentiating between social costs and economic impacts. It is critical that proper analysis not violate economic theory and the principles of benefit-cost analysis in doing so. The commentor suggests EPA should consider the following when calculating full societal costs:

(1) potential shut down of or decreased capacity in EGUs
(2) Higher energy costs
(3) Loss of jobs
(4) Loss of income
(5) Loss of energy security

We address each of these separately.

(1) Potential shut down or decreased capacity in EGUs. In fact the IPM model used by EPA to estimate costs and other impacts, does provide an estimate of EGU shutdowns and decreased capacity, if relevant. The IPM model estimates the costs of meeting the U.S. demand for electricity. To the extent that some EGUs shutdown, the model must replace that lost capacity with other capacity. The cost of replacing this lost capacity is estimated by IPM. Hence, we want to be clear that the cost of plant shut downs (in the form of higher electricity prices) is calculated and is part of our cost estimates we routinely calculate.

(2) Higher energy costs. It is true that pollution control requirements can lead to higher energy prices. The IPM model does provide estimates of higher energy prices as a result of the regulation.

(3) Loss of jobs. The commentor argues that the increased cost of electricity will lead to loss of jobs. It is true that higher electricity prices can ripple through the economy and disrupt particular industries. However, to a first approximation, the increased spending for pollution control equipment creates the same number of jobs as the loss in jobs from higher electricity prices. Hence, we generally consider job loss to be serious economic impact, worthy of consideration, but it is not, in general, considered to be a "net" cost of a regulation. In fact, job creation by a regulation is one component of the costs. WOrkers who make pollution control equipment must be paid. This is part of the cost of buying pollution control equipment.

There is, however, one mechanism that can lead to reduced labor hours in the economy that can be a cost. In the 1990's and beyond, economists have identified and investigated the so-called tax interaction effect. The problem arises because we the economy already taxes labor services a great deal. These labor taxes tend to generate too little labor being provided to the economy. Any regulation that gives rise to higher prices, can further depress the real wage. In doing so, workers provide even less labor services to the economy. While this is conceptually understood by economic modelers, the empirical estimates of this effect vary widely. Further, the benefits of environmental improvement tend to raise the productivity of the American worker. Reduced mercury, for example, will raise IQ levels in the economy. As workers get smarter, productivity increases. Hence, these type of interaction effects can affect both the costs and benefits.

(4) Loss of income -- as in the case of jobs, some workers will find themselves with higher income and some with lower income. In general, job losses (or gains) are not counted as social costs of the regulation.

(5) Loss of energy security. The IPM model does give estimates of the source fuels for the production of electricity. We will then be able to estimate whether imports of oil or natural gas (or other forms of energy) will go up or down as a result of this regulation.

Comment:

One commenter (OAR-2002-0056-5458) believed the benefits analysis must be focused on the neurodevelopmental health of children. In the benefit analysis referenced in the proposal and identified in the NODA, IQ reduction was chosen as the health endpoint to quantify the benefits of reducing MeHg exposure in children. The commenter is concerned about the use of IQ as the endpoint for benefits quantification across the three major epidemiological studies used to develop the MeHg reference dose (RID) because IQ was only directly measured in the New Zealand study. Based upon notes from the Mercury Neurotoxicity Workshop, the selection of IQ as the neurological endpoint for quantification seems to be based almost entirely on the fact that decrements in IQ can be monetized. The commenter will reserve its comments on this aspect of the benefits analysis until it is available for public review and comment.

Response:

Please see Chapter 9 of the RIA for a discussion of the derivation of the dose-response curve and Chaters 10 and 11 for a discussion of the monetized benefits.

Comment:

One commenter (OAR-2002-0056-5488) said that to date, the EPA has not assessed the public health benefits from reduced Hg exposure to the population, instead relying on analyses of public health co-benefits resulting from reduced exposure to criteria air pollutants. The NODA expresses the agency's intent to conduct analyses of the benefits resulting from avoidance of IQ reduction in children, but it does not specify the range of regulatory options to be considered. Within the NODA, the only two scenarios mentioned are the base case and the reductions afforded by the proposed CAMR. The commenter believed that such a limited analysis is entirely insufficient to justify the setting of Hg reduction levels on a health basis. The commenter requested that the EPA analyze and compare the public health benefits associated with Hg reduction levels that are more protective than those proposed under the CAMR and more consistent with Hg reductions levels demonstrated above to be achievable.

In addition, just as the agency relied on the co-benefits from reduction of criteria air pollutants in its initial benefit estimate of the proposed CAMR, in the revised benefits analysis, co-benefits from any additional reduction of criteria air pollutants as well as co-benefits of reductions in other toxic air pollutants must be added on to the benefits from avoidance of IQ

reduction related to reduced exposure to MeHg in each Hg reduction scenario modeled.

The commenter agreed with the agency that the avoidance of IQ reduction is the best studied and most easily monetized benefit of reduced MeHg exposure, and this outcome should be included in the revised benefits analysis. But other serious health effects must also be accounted for in EPA's benefits analysis. EPA's benefits analysis must give full consideration to the impacts on the immune and cardiovascular systems in addition to the nervous system. There is compelling evidence that additional health benefits result from reduced population exposure to MeHg beyond avoidance of IQ reduction. The commenter, therefore urged the agency to include in its analysis the cardiovascular and immune system effects of Hg and expressly acknowledge that the actual health benefits are greater than those estimated based on consideration of IQ effects (or reduced exposure to criteria air pollutants) alone. In addition, the agency must account for benefits from avoided neurological effects such as motor dysfunction that are not captured by estimates of lost income from IQ reduction.

The selection of an appropriate dose response model must ultimately depend on which model best fits the data. The combined data from the Seychelles, Faroe Islands, and New Zealand studies are well-modeled by a linear dose response curve. The use of a linear instead of a threshold model is supported by the EPA IRIS database, which notes that no threshold was detected for MeHg neurotoxicity in the Faroe Islands study, as well as the National Research Council report on MeHg. Use of a linear model will also facilitate the estimation of health benefits from MeHg reductions below the modest levels currently proposed in the CAMR. Accordingly, the best available science shows that a linear dose response model should be used to properly estimate the health benefits of Hg pollution control options.

Given the complexity of this type of analysis and its application in the regulatory setting, the commenter requested that all assumptions, methods and uncertainties in the modeling of Hg reduction benefits be clearly and publicly documented and thoroughly peer-reviewed by a balanced body of outside experts.

Response:

The RIA includes an assessment, to the extent possible given our scientific understanding of mercury and its behavior in the environment and impacts on human health, of the health benefits associated with the proposed regulatory options. Due to limitations in our current understanding of these technical areas related to mercury this benefit analysis is limited to the self-caught freshwater fish consumption pathway and to IQ deficits in prenatally-exposed infants. In keeping with precedent in evaluating benefits of air regulations (REFERENCE), co-benefits (in this case resulting from potential reductions in direct $PM_{2.5}$) are also included in the RIA.

EPA acknowledges that emission control equipment used to reduce mercury emissions may reduce emissions of other pollutants including PM and associated HAPs. While EPA has included an analysis of potential cobenefits associated with reductions in direct PM2.5,

limitations in our current understanding of differential toxicity prevent us from modeling health benefits from reduced exposure to HAPs associated with that PM. Similarly, while EPA concurs with the National Academy of Sciences, that a variety of health endpoints may be associated with methylmercury exposure in addition to IQ (e.g., immune system effects, cardiovascular mortality and additional neurodevelopmental endpoints), there is insufficient peer-reviewed evidence at this time for conducting formal analysis of these endpoints for inclusion in the primary benefits estimate.

Comment:

One commenter (OAR-2002-0056-5502) referenced MeHg and Cardiovascular Effects. Evidence that exposure to MeHg via fish consumption leads to a high risk of adverse cardiovascular events is generally lacking; published findings are contradictory and inconsistent nature, and associations weak. Multiple contributing factors for cardiovascular health and striking cultural differences in coronary heart disease rates contribute to overall weakness in findings. It does not appear that there is "emerging evidence" that MeHg has major effects on cardiovascular systems, nor is there good evidence for fish Hg diminishing the cardio-protective effect of fish intake.

IQ and Neurobehavioral Tests. IQ neither meets requirements for a well-defined health effect for MeHg exposure, nor has it been used as a primary health endpoint in the children's MeHg studies. Major barriers to conducting a meta-analysis of the Faeroe Islands, New Zealand and Seychelles Islands studies are: the heterogeneity of the study designs; the neurobehavioral test batteries administered; the ages at testing; the lack of a consistent pattern of significant results across studies (most results are non-significant; however); the differences in study populations; and the differences in confounders measured and included in the final multivariate models. These inconsistencies and other shortcomings are major barriers to conducting a valid meta-analysis of the cohort studies to date.

Use of a Linear Dose-Response Model. Alternatives to the K=1 model need to be considered. Published analyses of the Seychelles study suggest evidence for a non-linear association for one or two neurobehavioral test endpoints with a threshold that is consistent with previous estimates from the Iraqi study. Non-linear models need to be applied to New Zealand and Faroes results prior to making a final determination of the best model to fit these data. Further, a linear dose-response model is questionable given that the standard RID established by EPA assumes a threshold dose below which there is not likely to be an appreciable risk of deleterious effects during a lifetime.

Response:

EPA does not have access to the study data for the three key studies. The only data available to EPA are regression coefficients and other statistics that have been published by the study investigators. Therefore, EPA is not able to conduct any modeling that would examine alternative shapes to the dose-response relationship, including non-linear models. EPA's

analysis involves a statistical integration of linear dose-response functions that have been reported by the study investigators. We believe that use of a linear function, in conjunction with using a nonthreshold model, in our analysis is well-justified by the following considerations: 1) The National Research Council's 2000 report on methylmercury used linear model results for deriving benchmark doses, and cautioned against use of supralinear models; 2) the Faroe Islands research team reported that K-power models (with the NRC-recommended constraint of K ≥1, i.e. with supralinearity excluded) fit best with the linear specification, i.e. K=1; 3) linear model results are available for IQ for all three studies, and no non-linear model results are available from the three studies (except for Faroes log model), and raw data are not available to us for conducting analysis of dose-response shape or other issues; and 4) the lowest exposures in the Faroe Islands study overlap with U.S. exposure range, although there is less overlap with the other two studies. Nonetheless, EPA's Reference Dose and the analysis supporting its derivation was reviewed positively by the National Academcy of Sciences and the Agency continues to support its level and the implications. We conclude that any analysis of the IQ benefits needs to deploy several models -- with a threshold and without to capture the full range of uncertainty. EPA acknowledges that there are complexities, including a variety of potential confounders, that must be considered in relation to potential cardiovascular mortality linked to methylmercury exposure. For additional discussion of this endpoint, see Appendix D.

Comment:

One commenter (OAR-2002-0056-5535) stated that MeHg poisoning incidents, particularly the well-known incident in Minamata, Japan, have established Hg as a neurodevelopmental toxicant. Three prospective epidemiological studies, in the Faroe Islands, the Seychelles, and New Zealand, have been singled out over the past five years for the development of dose response calculations. The study in the Faroe Islands documented subtle deficits of several functional domains at prenatal MeHg exposure levels previously thought to be safe. This finding was in agreement with the New Zealand study, as well as cross-sectional epidemiological studies in French Guiana and the Amazon that also showed effects but do not lend themselves to dose-response analysis. Results from the Seychelles have not been concordant, however; to date, this prospective study has not shown effects. In keeping with prevailing standards of public health protection, EPA and the NAS have used the Faroe and New Zealand studies as the basis for regulatory decision making.

The Faroese study recently has been updated to include state of the art neurological testing administered to the cohort of children under study as they have matured. Previously, in a 1997 report on the Faroese population, researchers examined children at age 7 and reported on abnormalities in CNS-mediated functions (such as achievement of developmental milestones) and sensitive measures of neurological function (such as evoked potentials, visual and auditory acuity, and neuropsychological functions). The new data cover subsequent examinations of the Faroese children at age 14 years; tests included brainstem auditory evoked potentials (BAEP's). The authors report that the signal from the acoustic nerve to the brainstem was significantly delayed in a dose-related fashion with prenatal exposure to Hg. Because they observed this effect at both 7 and 14 years, the authors suggested that this effect of Hg on the developing brain

is irreversible. This Hg-associated delay in transmission appeared to be parallel to the effects on the child's cognitive function. The measurement of BAEPs is an objective assessment that is independent of confounding factors, such as age and socioeconomic. Most concerning, these children had an average exposure similar to the "safe" limit (i.e., the reference dose) recommended by EPA.

Although the mechanism by which MeHg adversely affects the developing brain is not completely understood, there are numerous ways that the compound has been shown to affect neurons. It causes biochemical and structural changes in mitochondria (the energy producer in the cell), disrupts protein synthesis, causes membrane damage in nerve cells, and may create free radicals that damage lipids and result in neuronal damage. Oxidative damage may be a factor in MeHg toxicity, since concentrations of the repair enzyme glutathione decline and then increase after exposure to MeHg. MeHg also has been shown to disrupt cell division and cell migration by disrupting structural microtubular proteins. None of these effects is likely to have a clear threshold below which it does not occur.

Other Important Health Endpoints

Beyond neurotoxicity, research links Hg with a host of other health effects. First, the impact of Hg on overall growth and development has been supported by data published since 2000. In the Faroese cohort, pre- and postnatal MeHg exposure was found to be associated with decreased postnatal growth, particularly before 18 months of age. The authors found that, "irrespective of duration of breast-feeding, a doubling of the Hg concentration in cord blood was associated with a decrease in weight and height." Second, Hg may have immunotoxic effects. Hg induces autoimmune disease in rodents. Highly susceptible mouse strains develop multiple autoimmune manifestations after exposure to inorganic Hg, including proliferation of lymphocytes, elevated levels of autoantibodies, overproduction of immunoglobulins (IgG and IgE), and circulating immune complexes that can clog the kidney and vasculature. Now, a recent cross-sectional study provides evidence that a population of Hg-exposed adults living in the Amazon region has an increased prevalence of elevated autoantibodies, indicative of autoimmune dysfunction.

Third, several studies have linked Hg exposure to cardiovascular disease. Although some fish species contain beneficial omega-3 fatty acids, and fish is a low-fat source of protein, recent studies raise the possibility that moderate Hg content in fish may in fact diminish the cardio-protective effect of fish intake. A 2000 study reported an association between moderate hair Hg content and accelerated progression of arteriosclerosis in the carotid arteries leading to the brain (determined by ultrasonographic assessment of common carotid intima-media thickness) in a prospective study among 1,014 men aged 42-60 years in Finland. Hair Hg levels greater than 2 ppm (well within the range of the U.S. adult population) showed a doubling of the risk of cardiovascular mortality. This study was recently updated and reported that Hg in hair above 2 ppm may be a risk factor for acute coronary events and cardiovascular disease, coronary heart disease, and all-cause mortality in middle-aged eastern Finnish men.

Similarly, a study published in the New England Journal of Medicine reported that toenail Hg level (an indicator of total Hg exposure) was directly associated with the risk of myocardial infarction. This case-control study was conducted in eight European countries and Israel, and studied 684 men with a first diagnosis of myocardial infarction. The authors report that the Hg levels in the patients were 15 percent higher than those in controls (95 percent confidence interval, 5 to 25 percent). The risk-factor-adjusted odds ratio for myocardial infarction associated with the highest as compared with the lowest quintile of Hg was 2.16, a more than twofold increase in the risk. The authors suggest certain mechanisms that may contribute to this effect, including inactivating the protective, antioxidant properties of the repair enzymes glutathione or catalase, inducing cell membrane damage by lipid peroxidation, promoting platelet aggregability and blood coagulability, and affecting the inflammatory response, among several others.

Although a third study on cardiovascular health was unable to replicate these findings, the study population consisted largely of dentists who had occupational exposure to elemental Hg. Since Hg exposure measurements in this study were based on total Hg, the elemental Hg exposure could have confounded detection of a MeHg effect. In fact, when the dentists were removed from the study, an association with cardiovascular outcomes (albeit not statistically significant, possibly due to the smaller sample size) was seen with Hg exposure.

The new data on MeHg indicate that neurodevelopmental effects are likely to be permanent and to be present-according to objective measures–at Hg levels lower than previously reported. It is also increasingly clear that the neurodevelopmental endpoint is not the only endpoint of concern for human health, and that the immunotoxicity of Hg will be an area of increasing concern in the future. The immunotoxicity issue is reason for an especially precautionary approach to development of a benefits calculation. The data on cardiovascular endpoints are sufficiently robust at this point that they should be included in a benefits assessment for Hg. The public health and economic burden of cardiovascular disease in the U.S. is very significant, and the effect of Hg, even if relatively modest, is significant and worthy of inclusion in the agency's estimate of the benefits of Hg regulation. In our opinion, it would be a mistake for the agency to ignore any of these endpoints in its benefits assessment, even though the commenter agreed that neurodevelopment in children is an especially important endpoint.

The focus on neurodevelopmental health of children

Although the commenter agreed that a credible benefits assessment for this rule should address the well-established neurodevelopmental health effects of Hg toxicity, they did not believe this should be the exclusive focus. A July 2000 review by the National Academy of Sciences (NAS) concluded that neurodevelopmental effects were the most sensitive and well-documented effects of MeHg exposure, based on the best available data at the time. EPA's RfD of 0.0001 milligrams per kilogram of body weight per day (mg/kg/day) derives from a neurodevelopmental endpoint, and the NAS determined that EPA's RfD "is a scientifically justified level for the protection of public health." The RfD was based on three epidemiological studies of prenatal MeHg exposure in the Faroe Islands, New Zealand, and Seychelles Islands.

These studies examined neurodevelopmental outcomes through the administration of numerous partial or full assessments of IQ, problem solving, social and adaptive behavior, language functions, motor skills, attention, memory, and other functions. Although the NAS panel found that all three studies are well-designed, prospective, longitudinal studies, it also concluded that, "given the strengths of the Faroe Islands study, it is the most appropriate study for deriving an RfD."

However, as discussed above, Hg exposure has also now been linked to immune system dysfunction, other developmental effects, and cardiovascular disease. These potentially permanent, severe, and life-threatening effects are associated with environmentally relevant levels of Hg exposure. When calculating the benefits of reducing Hg exposure it would be a mistake to focus on the neurodevelopmental outcomes to the exclusion of all of these other important health endpoints. To do so would ignore the extensive new scientific information on MeHg and would also seriously underestimate the health benefits of Hg reduction.

IQ as an endpoint for quantification of neurodevelopmental effects

EPA asks for comments regarding whether IQ is an appropriate metric for quantifying neurodevelopmental impacts. It is not a sufficient one. The array of neuropsychological deficits associated with even low levels of Hg exposure during early life stages includes behavioral alterations and impaired language, attention, memory, and, to a lesser extent, visuospatial and motor functions. Most concerning, some of these effects are detectable at exposure levels currently considered acceptable by EPA. It is clear that Hg effects are not localized to discrete brain regions when these exposures occur prenatally or perinatally, and any credible benefits analysis must quantitatively account for the broad spectrum of brain damage associated with Hg. Measurements of IQ are inadequate to capture fully the profile of Hg neurodevelopmental toxicity; IQ tests do not capture impairments of manual dexterity, motor functions, and hand-eye coordination, all known to be associated with Hg exposure. Accordingly, to be more credible, a benefits analysis must explicitly calculate the sweeping benefits of reduced exposure for protection of the fragile, complex developing nervous system.

Quantification and economic valuation of neurodevelopmental and other health effects

An economic valuation will not be complete unless it can account for adverse effects of early-life exposure to Hg on cognitive abilities, neurodevelopmental deficits such as motor disabilities and hand-eye co-ordination, immune system toxicity, impaired growth and development, and cardiovascular disease. A full economic valuation of Hg toxicity must quantitatively account for the full array of neurodevelopmental deficits known to be associated with Hg, such as learning, memory, IQ, visuospatial, and motor deficits. In addition, an economic valuation that claims to represent Hg toxicity must also account for Hg-associated immunotoxicity, reproductive effects and cardiovascular disease risks. If this cannot be done, perhaps because the data are not sufficiently robust for such a calculation, then the resulting uncertainty and potential for error must be stated, and incorporated into the final analysis.

The commenter supported a comprehensive approach for the development of a credible benefits analysis, but emphasized that any such analysis must consider the variability within the data and the uncertainty inherent in the exposure assessment and model methodology. It may be helpful in developing an integrative, data-comprehensive benefits model, for EPA to review the NAS report. The NAS used data from the Faroe Islands, New Zealand, and the Seychelles Islands studies to develop an integrative analysis of Hg toxicity. EPA itself developed the RfD of 0.1 g/kg body weight per day for MeHg by integrating data from these three studies, so it is apparent that the agency is capable of such an integrated assessment. It is consistent with EPA practice to consider the weight of evidence of the available literature. The NAS approach relied upon a hierarchical random effects model designed to take proper account of appropriate study-to-study and outcome-to-outcome heterogeneity across the studies. Such a model provided a useful tool for separating random versus systematic variation and thereby provides more stable estimates of study-specific and outcome-specific benchmark doses. The effect of the hierarchical modeling was to smooth away much of the random variability observed in the original data, particularly the more extreme values.

Use of the K=1 model

PA seeks comment on whether, by using a K-model with K=1, it should presume that reducing Hg exposure will reduce adverse health effects in a linear fashion. The researchers analyzing data from the Faroe Islands study have investigated various models applied to their data set. They have found that a log curve is the best fit with the data, but the improvement over a linear curve is of borderline statistical significance (p=0.06). Accordingly, the researchers have used a linear model for their analyses. It appears that the choice of either a linear or a log model is reasonable. It would be unreasonable, however, for the agency to continue the past practice of using a threshold model with a NOAEL, as such a model is unsupported by the existing data.

An alternative approach could involve doing a benchmark dose extrapolation that incorporates all available data on Hg toxicity. The benchmark dose (BMDL) method is coming into increasing use as a pragmatic way of dealing with dose-response relationships deriving from multiple endpoints and multiple datasets, without a clear indication of a threshold, such as the Hg data. The BMDL is the lower 95 percent confidence limit of the dose of a substance that increases the risk of an abnormal response by a benchmark response, such as a 5-10 percent response compared with a reference population. Such an approach would require the use of an uncertainty factor; because a BMDL is not a no-effect level, an additional multiplier is necessary to provide sufficient assurance that the public at large would be protected from an adverse health effect.

Use of a linear dose-response model and the appropriateness of assuming that Hg has a threshold for adverse health effects

The data from the Faroe Islands study do not reveal evidence of a threshold below which Hg does not exhibit some toxic effect on the developing brain. Mechanistic data also support the

lack of a threshold, as Hg has numerous adverse effects on neurons that would not be expected to have a threshold of action. Therefore the choice of a linear model makes the most sense for analysis of the MeHg data.

Recent data from the Faroe Islands study indicate that the BMDL for deficits in neurophysiological function is more likely to be associated with 5 µg/g Hg in hair, instead of the 11 µg/g that the NAS calculated, meaning that the neurological effects of Hg have been demonstrated at an even lower dose than previously reported. The difference is due to exposure misclassification. All calculations so far have assumed that the exposure estimates were more precise than they really are. The Faroe Islands research team recently showed that hair-Hg is somewhat imprecise-that is, in this case, how well the hair measurements reflected the true cord-blood Hg exposure. Imprecise exposure assessments result in an underestimation of the true magnitude of the effect of an exposure to MeHg. Recalculation of the benchmark dose indicated that it had been overestimated by a factor of two. Accordingly, recalculating the exposure limit using the adjusted benchmark dose would result in a limit approximately one-half the one used by EPA in calculating the RfD.

The commenter was also concerned about potential industry pressure on EPA to revise the RfD or to undermine any conclusions the agency has made about risks to the U.S. population. The commenter was aware that agency officials met with seafood industry representatives in February 2004. Accordingly, the Clean Air Task Force requested disclosure of materials related to this meeting (and any other materials related to this or other similar meetings) pursuant to the Freedom of Information Act, 5 U.S.C. §552. Although EPA received that request on November 2, 2004 and is required to "respond to requests no later than 20 working days from the date the request is received and logged in," 40 CFR §2.104(a), the agency has not provided the Clean Air Task Force with a substantive response. The commenter is looking forward to the agency's response so that they can be assured that the seafood industry has not prompted EPA's newfound interest in the RfD.

Response:

In developing the RfD, the Agency did rely on benchmark dose modeling as the most appropriate method of quantifying the dose-effect relationship in the three principal studies, which was also the recommendation of the NRC (2000). EPA chose not to make a numerical adjustment between cord-blood and maternal-blood mercury. The relationship between cord-blood and maternal-blood mercury is considered subject to variability and uncertainty, and was included in the determination of the uncertainty factor.

The RIA includes an assessment, to the extent possible given our scientific understanding of mercury and its behavior in the environment and impacts on human health, of the health benefits associated with the proposed regulatory options. Due to limitations in our current understanding of these technical areas related to mercury this benefit analysis is limited to the self-caught freshwater fish consumption pathway and to IQ deficits in prenatally-exposed infants. In keeping with precedent in evaluating benefits of air regulations (REFERENCE), co-

benefits (in this case resulting from potential reductions in direct $PM_{2.5}$) are also included in the RIA.

EPA concurs with the National Academy of Sciences, that a variety of health endpoints may be associated with methylmercury exposure in addition to IQ (e.g., immune system effects, cardiovascular mortality and additional neurodevelopmental endpoints). However, there is insufficient peer-reviewed evidence at this time for conducting formal analysis of these endpoints for inclusion in the primary benefits estimate.

EPA acknowledges that emission control equipment used to reduce mercury emissions may reduce emissions of other pollutants including PM and associated HAPs. While EPA has included an analysis of potential cobenefits associated with reductions in direct $PM_{2.5}$, limitations in our current understanding of differential toxicity prevent us from modeling health benefits from reduced exposure to HAPs associated with that PM. Similarly, while EPA concurs with the National Academy of Sciences, that a variety of health endpoints may be associated with methylmercury exposure in addition to IQ (e.g., immune system effects, cardiovascular mortality and additional neurodevelopmental endpoints), there is insufficient peer-reviewed evidence at this time for conducting formal analysis of these endpoints for inclusion in the primary benefits estimate.

Comment:

One commenter (OAR-2002-0056-5465) stated that at the most fundamental level, EPA's proposed revised benefits assessment appeared to suffer from the same flaw that undermined its initial benefits assessment for the CAMR: while EPA proposed to account for the costs and benefits of the Maximum Achievable Control Technology (MACT) and cap-and-trade alternatives as proposed by EPA in its January 30,2004 proposed rule, EPA failed to consider whether a more protective rule would produce an even more favorable accounting of costs and benefits. As Professors Heinzerling and Steinzor document, this failure stood in stark contrast to the current practice of the Office of Management and Budget's Office of Information and Regulatory Affairs in implementing EO12866. Moreover, as numerous commenters have pointed out, EPA's proposed approaches rest on dubious scientific and legal footing; a legally defensible rule would in fact require much more stringent reductions in Hg emissions from coal-fired utilities. Against this backdrop, EPA's failure to consider the costs and benefits of a more stringent rule is particularly egregious.

Second, as EPA now concedes, it cannot accurately assess the benefits of Hg emissions regulation without considering the independent benefits of reducing the adverse effects of Hg contamination. However, in order to produce an accurate accounting, EPA must not define narrowly the benefits at issue, i.e., EPA cannot consider only a subset of the direct effects on human health (and then only those that are quantifiable or monetizable). Instead, EPA must consider broadly the direct and indirect effects on human health and well-being. Included within this broader definition are those effects felt not only by individual humans but also by relevant groups (e.g., adverse impacts on the various Ojibwe and other tribes' ability to continue

important traditional, cultural and religious practices). EPA must also consider the effects on ecological health. The commenter thus urged EPA to refer to those tribal and other commenters, e.g., the Forest County Potawatomi Community and the Fond du Lac Tribe, that have know ledge of and are uniquely positioned to speak to the nature and extent of the adverse effects of Hg contamination.

Finally, EPA does not appear to contemplate any assessment of the distribution of the costs and benefits of the CAMR and more protective alternatives. However, as Professor O'Neill demonstrates, various subpopulations' different circumstances of exposure mean that the adverse effects of Hg reductions that are delayed and/or diminished will not be distributed equally. Rather, the harms will be visited disproportionately on American Indian tribes and their members–especially those in the Great Lakes states, where there is a likelihood of "hot spots" under the EPA's proposed cap-and-trade approach–and on other communities of color and low-income groups. Indeed, it is clear from the preamble to the proposed CAMR that the EPA is well aware of who it is that will be adversely affected by a more lenient rule. In order to fulfill its obligations under EO12898 regarding environmental justice–as well as its obligations under the federal trust responsibility, treaties, and various other legal doctrines–EPA must assess and address the distributive implications of its proposed rule.

Response:

EPA included four potentially high-risk populations in the RIA, including: (a) high-end recreational fisher anglers (with consumption rates at or above the 95th percentile for this group), (b) economically disadvantaged high-end consumers with poverty-status income and fish consumption rates at or above the 95th percentile for freshwater anglers, (c) Hmong in Minnesota and Wisconsin and (d) Chippewa in Minnesota, Wisconsin and Michigan. These special population are intended to provide coverage for groups of individuals who through choice, necessity or socio-cultural practices consume relatively high levels of self-caught freshwater fish. Inclusion of these four special populations is also intended to support consideration of distributional/equity in relation to EGU-based environmental regulation (i.e., would a subset of the US population benefit disproportionately from regulations to reduce mercury emissions from EGUs)?

Fish consumption rates for all four special populations have been developed based on peer-reviewed survey data that are representative of the particular group of interest. In the case of the Chippewa, we have used a mean value obtained from the literature (see RIA Chapter 10 for additional details). However, it was not possible to identify a high-end percentile consumption rate based on peer-reviewed literature and consequently, the mean consumption rate was used in the benefits analysis without consideration for variability in fish consumption rates across individuals. However, in response to information (including that provided by this commentor), EPA has conducted a sensitivity analysis for high end fish consumption by the Chippewa population using (a) the maximum delta fish tissue concentration modeled in the RIA for Option 1 and Option 2 for the Chippewa (i.e., the maximum change in MeHg fish tissue concentrations modeled for the Chippewa under CAMR Options 1 and 2) and (b) the maximum seasonal fish consumption rate provided in the NODA comments (i.e., 393.8 g/day). The results

suggest that total IQ reductions under Option 1 and 2, even under these conservative assumptions (i.e., highest change in mercury fish tissue concentrations under Option 1 and Option 2 and the highest seasonal fish consumption rate), are relatively low at 0.02 IQ points per child. This relatively low IQ benefit for this conservative scenario reflects the fact that, while states where the Chippewa are located may have relatively high absolute (total) MeHg concentrations in target fish species, modeled EGU deposition over these areas is relatively low and consequently, CAMR is likely to produce smaller changes in mercury fish tissue concentrations compared with other areas where EGU deposition is higher. These findings argue against a distributional equity concern for the Chippewa in this portion of the study area (although this conclusion needs to be considered in the context of the overall precision and specificity of the benefits model used in this RIA which is not intended for site-specific analysis and was developed for application at the regional-level).

EPA has used a cost-of-illness function based on lost earnings resulting from methylmercury exposure as the basis for its primary benefits estimate in the RIA (i.e., prenatal methylmercury exposure through maternal consumption producing IQ decrements in children which translate into lost earnings later in life). This valuation function, which is based on the approach used in past EPA regulations concerning lead exposure, also considers the impact of lowered IQ on years of education achieved. EPA acknowledges that because this function is based on cost-of-illness and not willingness-to-pay (WTP), it likely represents a lower bound for valuation of the IQ decrements and that a more comprehensive WTP-based function would capture other factors such as those listed by the commentor above. Note, EPA did not use a WTP-based function in the benefits analysis because peer-reviewed literature does not support derivation of such a function at this time.

Comment:

One commenter (OAR-2002-0056-5571) noted that EPA has requested comments as to how reductions in population-level exposures of Hg will improve public health. (Question 1) The commenter noted that it is important to understand that there is a threshold for Hg levels in the blood below which there are no effects. This is in contrast to lead, which appears to have no clear threshold level. Unlike lead a significant (>50 percent) percentage of atmospheric Hg is from natural sources. Mercury has been present in fish tissue prior to the industrial revolution. EPA has selected an RfD for Hg in maternal blood (5.8 ppb) that serves as a de-facto threshold. This number, which is 10 times below the threshold number developed from the Faroe Islands study and 14 times lower than the WHO level of concern, is very conservative. This commenter believes that if an unrealistically low threshold (ULT) for Hg blood levels were used to estimate benefits, reductions in blood levels between the true threshold and the ULT would create the appearance of a benefit where there is none.

EPA has requested comments as to the appropriateness of using IQ as an endpoint for both quantifying neurological development and the benefit analysis for reduced exposure to MeHg. In addition, EPA requested comments on the appropriateness of a linear dose response model evaluating health impacts. The commenter noted that there is a concern that EPA may wish to develop a relationship between Hg emissions and general population IQ. If this

relationship were then coupled with an imputed value for increased IQ for the general population, large estimated benefits could be generated that would not exist, since there is no evidence of IQ impact at blood Hg levels greater than the RfD but below the Faroe Island threshold level. There are opportunities to calculate an imputed value for IQ changes, for example, recent work by Jones and Schneider estimates that a 1 point increase in national IQ is associated with a 0.16 percent annual increase in GNP. This commenter believes that there is also a concern that assuming a linear response between blood Hg and IQ would lead to an imputed benefit for reducing blood Hg below the threshold level, again creating benefits that do not exist.

Comment:

One commenter (OAR-2002-0056-5571) notes that EPA's successful lead reduction program is not an appropriate model for Hg. Lead is a pollutant that has been linked to neurological damage similar to that of Hg. In the late 1970s, EPA initiated a successful program designed to eliminate all lead emissions into the environment primarily through the phase-out of leaded gasoline. Since airborne lead emissions are linked to blood lead levels in children and related neurological impacts, it may appear reasonable to utilize the lead elimination model for dealing with Hg. However, there are important reasons why the program to reduce lead (total elimination of air emissions) is not appropriate for dealing with Hg.

- Virtually all airborne lead is attributed to anthropogenic sources while a large percentage of airborne Hg (>50 percent) is due to natural sources. It is impossible to eliminate all airborne Hg emissions.

- Lead emissions and ambient lead concentrations are primarily associated with urban areas while Hg emissions and ambient Hg concentration are global.

- While there appears to be no lower limit for neurological impacts for lead blood levels, Hg blood levels have a clear threshold below which there are no neurological impacts.

- While neurological impacts were clearly shown at blood lead levels present in urban US children in the 1970s, no such neurological impacts have been noted or documented at Hg blood levels currently found in American child-bearing age women or children.

This commenter believes that EPA should consider the loss of health benefits associated with reduced fish consumption due to an overly conservative RID for Hg blood levels in determining net health benefits due to the CAMR. The vast majority of health studies have concluded that the benefits of fish consumption by all segments of the general population far outweigh any effects due to blood Hg levels greater than EPA's RID and at levels approaching the WHO level of concern. The use of the RID as the basis for calculating fish warning Hg levels has resulted in a reduction in fish consumption and the related loss of health benefits to the public. The commenter supports the comments of the Center for Science and Public Policy in this regard.

In conclusion, the commenter believes that the combination of (1) an overly conservative blood Hg threshold and a linear dose response with assumed benefits accruing below the threshold level along with (2) the failure to properly account for the loss of health benefits due to reduced fish consumption based on EPA's RID will produce unwarranted and unrealistically high estimated benefits from Hg emission reductions from the proposed CAMR.

Response:

As described in other responses, the Agency has high confidence in the RfD for methylmercury. EPA encourages the public to vary the species and sources of fish in order to obtain the benefits of fish consumption while avoiding elevated exposures to methylmercury. The fish advisory developed jointly with the Food and Drug Administration emphasizes the benefits of including fish in a healthy diet while informing the public on ways to reduce methylmercury exposure (http://www.epa.gov/waterscience/fishadvice/advice.html).

Comment:

The commenter (OAR-2002-0056-5455) also wished to comment on Step 5 of the NODA addressing cost/benefit analyses and how Hg reduction will improve human health. The commenter found that EPA's benefits analysis did nothing to address the importance of fishing as a cultural practice. There was no way to place a dollar amount on the benefit to spiritual well being as a result of practicing a centuries-old tradition and passing it on to our children. In a more concrete measurement, EPA did nothing to address replacing a subsistence food source that provided a significant amount of nutrition for the commenter's members. In making a local, easily obtainable food source inedible due to poisoning, EPA should calculate the costs that will be incurred in finding alternate sources of nutrition. The commenter was also unaware of any attempts EPA had made to quantify the costs of the learning and educational problems that exposed children may experience. For example, the loss in lifetime earnings resulting from lowered IQ's in the generalized population as a result of Hg poisoning has been estimated at $2.3 billion per year. By refusing to set adequate MACT standards, EPA was heaping most of this loss on the heads of native people. Another error in EPA's cost/benefit analysis came from the projection of $15 billion in savings due to health-related benefits from their proposed rule. These were simply health benefits that accrued from EPA's very substandard proposal. If a proper MACT standard were set in place, additional billions of dollars could be saved.

EPA had also failed to assess tourism-related impacts. Tourism brought in $9.8 billion annually in Minnesota alone. Of this total, sport fishing enthusiasts spend $1.58 billion, or 16 percent. Although it was unknown to what level fish advisories impacted these number, fishing and tourism brought in income that the state of Minnesota could not afford to lose. The other Great Lakes states of Wisconsin, Michigan, Illinois, Indiana, and Ohio face similar situations. Together, these states, along with Minnesota, attract 7.8 million anglers annually who spend $5 billion in fishing-related dollars. Although these are not directly health-related issues, they certainly need to be addressed in EPA's economic considerations.

Response:

EPA has used a cost-of-illness function based on lost earnings resulting from methylmercury exposure as the basis for its primary benefits estimate in the RIA (i.e., prenatal methylmercury exposure through maternal consumption producing IQ decrements in children which translate into lost earnings later in life). This valuation function, which is based on the approach used in past EPA regulations concerning lead exposure, also considers the impact of lowered IQ on years of education achieved. EPA acknowledges that because this function is based on cost-of-illness and not willingness-to-pay (WTP), it likely represents a lower bound for valuation of the IQ decrements and that a more comprehensive WTP-based function would capture other factors such as those listed by the commentor above. Note, EPA did not use a WTP-based function in the benefits analysis because peer-reviewed literature does not support derivation of such a function at this time.

Comment:

Four commenters (OAR-2002-0056-2224, -2835, -2867, -2922) filed comments to supplement EPA's discussion of its statutory authority to regulate under CAA section 111 and to establish a cap-and-trade program. They stated that CAA section 111 confers broad legal authority for the regulation of existing sources under a Federal-State partnership. The legislative history and the relationship between the plans developed for the State-Federal partnerships under CAA section 110 and section 111 further supports EPA's determination that a flexible emissions trading program can be implemented under section 111(d).

The commenters noted that this partnership contemplates EPA establishing "standards of performance" at the national level and each state developing a regulatory program for implementing and enforcing those standards at the state level. The commenters pointed out that the statute explicitly notes that the Federal-State partnership under CAA section 111(d) is to be modeled after the regulatory process used under CAA section 110. In that regulatory context, CAA section 110 provides States with wide latitude in developing emissions control strategies for achieving Federal air quality goals — National Ambient Air Quality Standards (NAAQS) established by EPA at the national level.

Both the statute and legislative history confirm that Congress delegated broad legal authority to adopt flexible regulatory mechanisms for controlling existing sources under section 111(d)(1). This broad delegation of authority provides sufficient authority for EPA to establish flexible "standards of performance" that need not prescribe when, how, and the degree to which each affected unit must achieve that emissions limitation — either on a unit-by-unit basis or facility-by-facility basis. In addition, the CAA authorizes States to implement and enforce those standards of performance through cap-and-trade program or other such flexible, market-based mechanism that implements the reduction requirement imposed under the standard of performance, while taking into consideration "the remaining useful life" of the source as well as "other factors." EPA's proposed trading scheme is one effective mechanism for States to address concerns regarding existing units whose remaining useful life is limited such that the

purchase of allowances may be appropriate in lieu of making additional major pollution control investments at those units. Commenter OAR-2002-0056-2835 described in detail how this interpretation is confirmed in the legislative history to CAA section 111(d).

Another indication of the broad discretion accorded to EPA and States in implementing and enforcing standards of performance under section 111 (d)(1) is the relationship that this section has with section 110. Section 111 (d)(1) requires EPA to promulgate regulations that establish SIP-like procedures similar to those in section 110 to be used by States in submitting their plans. The CAA section 111(d) plans and SIP programs are complementary to one another – in particular, a State's plan under section 110 (or section 172, for non-attainment areas) can be used to meet the standards under section 111(d). States can thus use the SIP regulatory tools in CAA sections 110(a)(2)(A) and 172(c)(6) to establish "enforceable emissions limitations and other control measures" to achieve this end. One such regulatory tool available to States explicitly referenced under these sections is the adoption of "economic incentives such as fees, marketable permits, and auctions of emissions rights," when developing a plan to comply with the standards under section 111(d)(1).

This complementary relationship was confirmed in EPA's guidance for implementing the Emission Guidelines for Municipal Waste Combustors established under CAA sections 111(d) and 129. EPA's guidance explained that where the SIP requirements are adequate to meet the section 111(d)/129 standard - which are required to be more rigorous than emission guidelines under only section 111(d) - the State has the authority to submit a section 111(d)/129 plan that relies on the requirements of the SIP to meet the section 111 (d)/129 standard. The commenter adds that the section 111(d)/129 rule for Municipal Waste Combustors also clearly contemplated that States would use trading when implementing and enforcing the standards-the rule explicitly provided that a state plan could "establish a program to allow owners or operators of municipal waste combustor plants to engage in trading of nitrogen oxides emission credits."

Commenter OAR-2002-0056-2867 stated that EPA has correctly harmonized these conflicting statutory provisions, and interpreted them in a way that effectuates the purposes of the statute as whole. The commenter agreed that the key provision in the definition of a "standard of performance" under CAA section 111 is the phrase "the best system of emissions reduction." Since this phrase is not defined by statute, EPA has broad discretion in determining what is the "best system of emissions reduction," so long as the system ultimately selected "has been adequately demonstrated." The commenter pointed out the definition places no other explicit statutory constraints on EPA in making this determination, except that it must consider the following factors: the cost of achieving the Hg reductions, non-air quality health and environmental impacts, and energy requirements. The commenter concluded that the statute requires the standards of performance be based on "the degree of emission limitation achievable" by the best system of emissions reduction system selected by EPA. As evidenced by the success of other cap-and-trade programs for the power sector, i.e., the NO_x SIP Call and the Title IV Acid Rain Program, the trading program approach arguably satisfies the statutory requirement for setting the standard of performance based on the best system of emission reduction for the electric utility source category.

The commenter felt it is important to note that the statutory definition does not require specific units or facilities to install emissions control technology. In addition, the definition is silent on whether or not the standard of performance prescribing specific emissions limits should directly apply on a unit-by-unit or facility-by-facility basis. The commenter also noted that the definition is silent on whether each unit or facility must achieve specific reduction levels continuously or averaged over a specific period of time. (Regarding this issue, the commenter pointed out that CAA section 302(1) also contains a definition of the term "standard of performance," which defines the term to mean "a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous emissions reduction." It appears to the commenter that this definition would not be controlling for purposes of setting standards of performance under section 111, given that Congress chose to adopt another specific definition of standard of performance in CAA section 111.

Three commenters (OAR-2002-0056-2224, -2835, -2867) emphasized that CAA section 111(d)(1) itself does not independently mandate that standards of performance for existing sources impose a source-specific requirement for continuous emission reduction. Thus, a State plan incorporating a standard of performance that employs a cap-and-trade mechanism would not conflict with the statutory requirements of section 111(d)(1). However, a strong case can be made for the proposition that the emissions cap and allowance-holding requirement in EPA's proposed section 111(d) trading program impose a "continuous emissions reduction" requirement on affected electric utility units. The proposed cap-and-trade program establishes a permanent cap on Hg emissions and requires affected sources to hold allowances that correspond to the level of Hg emissions from those sources at all times. By its very elements, the proposed cap-and-trade program is a continuous method of emission reduction given that there is no point in time when an affected source can emit Hg without holding allowances that correspond to those emissions. EPA's proposal also requires continuous emissions monitoring to assure that a source complies with the requirements of the cap-and-trade program at all times. Thus, if a court were ever to construe section 111(d)(1) to require a "continuous emission reduction," the features of EPA's proposed trading program should meet that requirement.

The legislative history of the term "standard of performance," does not specifically reference an allowance trading system as a regulatory mechanism for controlling emissions under CAA section111(d), but generally reflects Congress' intent that existing sources be accorded considerable flexibility in meeting the section 111(d) standards. Such legislative intent for compliance flexibility provides general support for EPA's interpretation that the term "standard of performance" may include an allowance trading program, as proposed in the Hg rule, because such a trading program accords flexibility to sources.

According to the commenter, the Senate debate on the 1990 amendments reinforces this statutory interpretation, in light of Congress' express action removing any specific percent reduction requirement from the concept of "standards of performance." As an example, the commenter states that Senator Baucus explains that Congress adopted a percentage reduction requirement in the 1977 CAA Amendments to ensure that coal-fired electric generating units did

not rely on low-sulfur "compliance" coal alone to meet NSPS for SO_2. According to Senator Baucus, a percentage reduction requirement across the board was supposed to require SO_2 scrubbers regardless of the rank of coal combusted; however, this approach accentuated the regional split over coal use that existed prior to 1977. With the adoption of the SO_2 emissions cap under the Title IV acid rain program, the percentage reduction requirement was no longer necessary and could in fact be a barrier to flexible compliance under the acid rain trading program. The commenter continues that accordingly, Congress elected to repeal the percent reduction requirement during the 1990 CAA Amendments.

The commenter also referenced remarks in debate by Senator Bond during the 1990 CAA Amendments that also pertain to the removal of the percentage reduction requirement and, indirectly, the continuous emission reduction requirement. Specifically, Senator Bond explained that both the House and the Senate rejected the concept of the percentage reduction and "directed EPA to come up with an alternative standard that would allow utilities to meet it in the most flexible manner possible." Senator Bond further noted that the new standards could be met by fuel switching, the use of technology and fuel switching, by technology alone, and by intermittent controls or intermittent operation. Senator Bond continued by stating that "[t]he way the language is constructed, intermittent controls can be allowed to comply with this section of the act. So for the first time in 13 years we will have EPA setting. . . emission levels for SO_2 that will not require the use of the scrubbers for compliance."

The commenter stated that this flexibility was not intended to be limited to utility standards, or the operation of the Acid Rain Program, but was to be afforded to all sources subject to "standards of performance" under section 111. The commenter felt it would be ironic if EPA failed to take advantage of the flexibility specifically intended by Congress to benefit the utility industry in the context of developing requirements for Hg control, since EPA itself has not identified any particular control technology as the basis for its standards.

Response:

Section 111(d)(1) authorizes EPA to promulgate regulations that establish a State Implementation Plan-like (SIP-like) procedure under which each State submits to EPA a plan that, under subparagraph (A), "establishes standards of performance for any existing source" for certain air pollutants, and which, under subparagraph (B), "provides for the implementation and enforcement of such standards of performance." Paragraph (1) continues, "Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."

Section 111(a) defines, "(f)or purposes of...section (111)," the term "standard of performance" to mean

a standard for emissions of air pollutants which reflects the degree of emission

limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Taken together, these provisions authorize EPA to promulgate a "standard of performance" that States must, through a SIP-like system, apply to existing sources. A "standard of performance" is defined as a rule that reflects emission limits to the degree achievable through "the best system of emission reduction" that EPA "determines has been adequately demonstrated," considering costs and other factors.

A cap-and-trade program reduces the overall amount of emissions by (i) requiring sources to hold allowances to cover their emissions on a one-for-one basis; (ii) limiting overall allowances so that they cannot exceed specified levels (the "cap"); and (iii) reducing the cap to less than the amount of emissions actually emitted, or allowed to be emitted, at the start of the program. In addition, the cap may be reduced further over time. Authorizing the allowances to be traded maximizes the cost-effectiveness of the emissions reductions in accordance with market forces. Sources have an incentive to endeavor to reduce their emissions cost-effectively; if they can reduce emissions below the number of allowances they receive, they may then sell their excess allowances on the open market. On the other hand, sources have an incentive to not put on controls that cost more than the allowances they may buy on the open market.

The term "standard of performance" is not explicitly defined to include or exclude an emissions cap and allowance trading program. In today's action, EPA finalizes its proposal to interpret the term "standard of performance," as applied to existing sources, to include a cap-and-trade program.

Because Congress did not speak precisely to this issue, EPA's interpretation of the term to authorize a cap-and-trade program is entitled to deference and should be upheld by a Court because the interpretation is reasonable. Chevron, U.S.A., Inc. v. Natural Resources Defense Council, Inc., 467 U.S. 837, 842-73 (1984). This interpretation is supported by a careful reading of the section 111(a) definition of the term, quoted above.

In the phrase, "standard of performance," the first operative term is "standard" and the standard must be "for emissions of air pollutants." The ordinary definition of "standard" is "[a]n accepted measure of comparison for quantitative or qualitative value," or "criterion." Webster's II New Riverside University Dictionary 1131 (1984). Under the cap-and-trade requirement, each existing source is obligated to hold an allowance for each unit of mercury that it emits. This requirement to hold allowances sufficient to cover emissions meets the definition of the term, "standard" because the requirement constitutes a means of measurement, or a type of a criterion, "for emissions of air pollutants." That is, the measure or criterion for a source's emissions of air pollutants is the amount of allowances that the source holds.

A cap-and-trade program is also consistent with the remaining components of the term "standard of performance," that is, the "standard for emissions of air pollutants" must be one

(i) "which reflects the degree of emission limitation achievable" (i.e., which requires an amount of emissions reductions that can be achieved), (ii) "through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[111]

The key component of the last part of this definition is the phrase, "best system of emission reduction." While the parenthetical following this phrase obligates EPA to consider the factors specified in that parenthetical, the term "best system" itself is not defined, and implicitly accords broad discretion to the Administrator. The term "system" implies a broad set of emissions reductions, and the term "best" confers upon the Administrator the authority to promulgate regulations requiring a system that he or she considers superior. The parenthetical phrase in the definition mandates consideration of certain factors, but the definition does not indicate how to weight those factors, how specifically to apply them, or whether other factors may be considered. Nor does the provision provide any other explicit constraints in determining the "best system." This broad authority conferred on the Administrator supports the view that the Administrator is authorized to interpret a cap-and-trade program as, under the present circumstances, the "best system," and thus as authorized under section 111(a) and (d).

Nor do any other provisions of section 111(d) indicate that the term "standard of performance" may not be defined to include a cap-and-trade program. Section 111(d)(1)(B) refers to the "implementation and enforcement of such standards of performance," and section 111(d)(1) refers to the State "in applying a standard of performance to any particular source," but all of these references readily accommodate a cap-and-trade program.

Although section 111(a) defines "standard of performance" for purposes of section 111, section 302(l) defines the same term, "(w)hen used in this Act," to mean "a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction." The term "continuous" is not defined in the CAA.

Because section 111(a) defines "standard of performance" for purposes of section 111, EPA believes that the section 302(l) definition does not apply to section 111. However, even if the section 302(l) definition applied to the term "standard of performance" as used in section 111(d)(1), EPA believes that a cap-and-trade program meets the definition. A cap-and-trade

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[1] The legislative history of the term, "standard of performance," does not address an allowance/trading system, but does indicate that Congress intended that existing sources be accorded flexibility in meeting the standards. See "Clean Air Act Amendments of 1977," Committee on Interstate and Foreign Commerce, H.R. Rep. No. 95-294 at 195, reprinted in 4 "A Legislative History of the Clean Air Act Amendments of 1977," Congressional Research Service, 2662. Because Congress intended flexibility for existing sources, EPA interprets this legislative history as generally supportive of interpreting "standard of performance" to include an allowance/trading program because such a program accords flexibility to sources. The legislative history contains no direct indication that Congress intended to preclude EPA from implementing section 111 for existing sources through a cap-and-trade program.

program with an overall cap set below current emissions is a "requirement of...emission reduction." Moreover, it is a requirement of "continuous" emissions reductions because all of a source's emissions must be covered by allowances sufficient to cover those emissions. That is, there is never a time when sources may emit without needing allowances to cover those emissions.[22]

We note that EPA has on one prior occasion authorized emissions trading under section 111(d). (The Emission Guidelines and Compliance Times for Large Municipal Waste Combustors that are Constructed on or Before September 20, 1994; 40 CFR Part 60, subpart Cb.) This provision allows for a NO_x trading program implemented by individual States. Section 60.33b(C)(2) states,

> *A State plan may establish a program to allow owners or operators of municipal waste combustor plants to engage in trading of nitrogen oxides emission credits. A trading program must be approved by the Administrator before implementation.*

Today's proposal is wholly consistent with this prior section 111(d) trading provision.

Having interpreted the term "standard of performance" to include a cap-and-trade program, EPA must next "determine" that such a system is "the best system of emissions reductions which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements)...has been adequately demonstrated." Section 111(a)(1). EPA has determined that a cap-and-trade program based on control technology available in the relevant time frame is the best system for reducing Hg emissions from existing coal-fired Utility Units.

Since the passage of the 1990 Amendments to the CAA, EPA has had significant experience with the cap-and-trade program for utilities. The 1990 Amendments provided, in Title IV, for the acid rain program, a national cap-and-trade program that covers SO_2 emissions from utilities. Title IV requires sources to hold allowances for each ton of SO_2 emissions, on a one-for-one basis. EPA allocates the allowances for annual periods, in amounts initially determined by the statute, that decrease further at a statutorily specified time. This program has resulted in an annual reduction in SO_2 emissions from utilities from 15.9 million tons in 1990 (the year the Amendments were enacted) to 10.6 million tons in 2003 (the most recent year for which data was available). Emissions in 2003 were 41 percent lower than 1980, despite a significant increase in electrical generation. At full implementation after 2010, emissions will be limited to 8.95 million tons, a 50 percent reduction from 1980 levels. The Acid Rain program allowed sources to trade allowances, thereby maximizing overall cost-effectiveness.

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[2] This interpretation of the term "continuous" is consistent with the legislative history of that term. See H.R. Rep. No. 95-294 at 92, reprinted in 4 Congressional Research Service, A Legislative History of the Clean Air Act Amendments of 1977, 2559.

In addition, in the 1998 NO_x SIP Call rulemaking, EPA promulgated a NO_x reduction requirement that affects 21 States and the District of Columbia ("Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule," 63 FR 57,356 (October 27, 1998)). All of the affected jurisdictions are implementing the requirements through a cap-and-trade program for NO_x emissions primarily from utilities.[33] These programs are contained in SIP that EPA has approved; and EPA is administering the trading programs. However, for most States, the requirements did not need to be implemented until May, 2004.

Further, EPA recently promulgated the Clean Air Implementation Rule (CAIR), which requires SIP revisions in 28 States and the District of Columbia to reduce emissions of SO2 and or Nox because those emissions contribute significantly to attainment problems for the PM2.5 or 8-hour ozone national ambient air quality standards in downwind States. The EPA Administrator signed the CAIR on March 10, 2005, and the rule and associated documents are available at http://www.epa.gov/cair/rule.html. Like the Nox SIP Call, in CAIR, EPA authorizes, and fully expects, the States to comply with the emissions reduction requirements through implementation of a cap-and-trade program.

The success of the Acid Rain and Nox SIP Call cap-and-trade programs for utility SO2 and Nox emissions, respectively, which EPA duplicated in large measure with the CAIR cap-and-trade programs, leads EPA to conclude that a cap-and-trade program for Hg emissions from utilities qualifies as the "best system of emission reductions" that "has been adequately demonstrated." A market system that employs a fixed tonnage limitation (or cap) for Hg sources from the power sector provides the greatest certainty that a specific level of emissions will be attained and maintained because a predetermined level of reductions is ensured. The EPA will administer a Hg trading program and will require the use of monitoring to allow both EPA and sources to track progress, ensure compliance, and provide credibility to the trading component of the program. The benefits of the cap-and-trade program are further described elsewhere in today's notice and in the separate Federal Register notice announcing EPA's revision of its December 2000 regulatory determination and removing Utility Units from the 112(c) list of categories.

EPA agrees that section 111(d), by relying on the Federal-state partnership, appears to incorporate the flexibility in type of acceptable State plan that is acceptable for purposes of section 110. The acceptability of cap-and-trade programs for section 110 SIP planning purposes suggests that they should be acceptable for section 111(d) state planning purposes.

EPA agrees that the statutory provisions that define "standard of performance" are silent on whether such standard applies on a unit-by-unit, facility-by-facility, or other basis; and are silent on whether the regulated entity must achieve specific reductions levels continuously, on an average basis, or on some other basis. Because the provisions are silent, EPA has authority to apply a reasonable interpretation, and EPA considers the cap-and-trade program to

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[3] Non-electricity generating units are also included in the States' programs.

be reasonable.

EPA further agrees that no provision of section 111(d) by its terms, nor any statements in the accompanying legislative history, suggest that a technological requirement, or any other specific requirement that is in the nature of a command-and-control requirement, must apply to each individual existing unit. EPA further agrees that statements in the legislative history emphasize the flexibility that States were to be accorded in fashioning plans for individual sources or groups of sources. H.R. Rep. No. 95-294 at 195, reprinted in Legislative History of the Clean Air Act Amendments of 1977 at 2662 (each state is to develop a "plan" that should "be based on the best available means (not necessarily technological) for categories of existing sources to reduce emissions;" EPA is to "establish guidelines as to what the best system is for each [category of sources];" states "are responsible for determining the applicability of [the] guidelines to any particular source or sources").

EPA further agrees that a cap-and-trade program is a mechanism for taking into account remaining useful life of the existing sources because it offers existing sources the opportunity to comply with requirements through the purchase of allowances, and that the consistency of a cap-and-trade program with the section 111(d) requirements lends further support for the reasonableness of interpreting the term "standard of performance" to authorize a cap-and-trade program.

EPA further agrees that statements in the 1990 legislative history describing the repeal of the percentage reduction requirements as designed to enhance flexibility offer further support for EPA's interpretation of section 111(d) to allow a cap-and-trade program. E.g., Senate Debate on the Clean Air Act Amendments of 1990 Conference Report, reprinted in 1 Legislative History of the Clean Air Act Amendments of 1990, at 1149 (statement of Sen. Simpson).

Comment

Four commenters (OAR-2002-0056-2359, -2823, -2920, -3459) contended that even if the regulation of HAP were available under 111(d), EPA's proposal under section 111(d) is not an adequate substitute for section 112 regulation. EPA acted arbitrarily and capriciously in implying that section 111 regulation, including a cap and trade approach, is adequate to address the harmful regional and local health and ecological impacts of HAP emissions from power plants (2823).

Response

EPA disagrees with commenters' view that the Title IV and Nox SIP Call programs do not provide useful precedent for a cap-and-trade program because, according to commenters those programs operated against a backdrop of other requirements for local controls, including SIP measures, NSPS provisions, and NSR requirements. EPA believes that the commenters are incorrect because many existing sources subject to Title IV or the Nox SIP Call are not subject to other control requirements (because, for example, they were in existence before the promulgation of otherwise applicable NSPS rules, they are in attainment areas and thereby

avoid nonattainment SIP requirements, and they have not taken actions that would subject themselves to PSD requirements). In any event, the utility of the Title IV and Nox SIP Call programs is that they demonstrated that their cap-and-trade programs succeeded in cost-effective achieving reductions

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EPA acknowledges commenters' views that in some instances, the cap-and-trade program may be associated with increased emissions, or, at least, emissions levels that stay constant, in a particular location or state. EPA modeled the effect of the cap-and-trade program on mercury emissions. The section 112 revision notice and accompanying documents describe the results, including the lack of "hot spots."

Comment:

One commenter (OAR-2002-0056-5570), responded to EPA's request for more information on the types of fish Americans eat and the concentrations of Hg found in these fish, the location where these fish are caught, and the types, amounts, location and Hg levels in fish consumed by highly exposed populations, the commenter would like to reiterate their previous point that relevant analysis has already been done and that EPA should utilize their own existing estimates for fish consumption patterns and vulnerable populations. Most notably, in preparation for the new joint EPA/FDA advisory on Hg in fish, both Agencies undertook an evaluation of consumption patterns, locations and vulnerable populations. In addition, external partners including a number of states and environmental and public health organizations have also tracked such data. Across all of these analyses, there is broad consensus about the pervasiveness of Hg contamination, and the high number of states with fish advisories for Hg.

In addition, the commenter would like to affirm EPA's apparent intent to look at susceptible populations (i.e., the tails of the fish consumption distribution, not just the average) to ensure that all Americans are adequately protected.

Response:

EPA appreciates the input from the commenter. We have carefully studied fish consumption patterns and our analysis is presented in the RIA and in the Effectiveness TSD.

Comment:

One commenter (OAR-2002-0056-5477) stated that recent scientific studies have confirmed the serious health risks to the developing fetus from MeHg exposure. In addition, recent studies confirm that a greater amount of MeHg is distributed to the fetus than previously estimated, leading to a doubling of an earlier annual estimate of newborn infants at risk in the U.S. from 300,000 to 600,000. In the Northeast, the prospect of over 84,000 newborns per year potentially at-risk for irreversible neurological deficits and cardiovascular abnormalities from MeHg exposure represents one of the most critical public health threats in our region today.

Over 15,000 fish samples collected in the Northeast region confirm widespread Hg contamination of our aquatic ecosystems, irreparably threatening human health and wildlife unless actions are taken to reduce significant sources of Hg emissions. All Northeast states have issued fish consumption advisories because of Hg contamination. In addition to the toll on human health and wildlife, Hg contamination also threatens the tourist and recreational fishing industries, which contribute $3 billion a year to our regional economy.

Recent scientific field studies have shown that reductions in Hg emissions lead to reductions in the Hg concentrations in fish tissue. After several years of implementing effective regulations to control Hg emissions from municipal waste combustors, medical waste incinerators, and other sources in the Northeast, the electric utility steam generating units (EGUs) remain the largest uncontrolled source category of Hg and other hazardous air pollutant (HAP) emissions in the region. Further, transported Hg emissions from out-of-region coal-fired EGUs are a major contributor to Hg deposition in the Northeast. In view of the public health and environmental impacts associated with exposure to Hg and other hazardous pollutants, the commenter believed it was extremely important that the EPA take swift and aggressive steps to reduce emissions of these pollutants from EGUs burning coal and oil.

Response:

We have carefully studied fish consumption patterns and our analysis is presented in the RIA and in the Effectiveness TSD.

Comment:

One commenter (OAR-2002-0056-5464) stated that another portion of the NODA on which EPA has requested comments is its proposed revised benefits analysis. The commenter reiterated that Section 112(d) is clear about the fact that MACT should be a technology-based approach, with requirements no less stringent than what well-controlled sources are accomplishing (i.e., "the average emission limitation achieved by the best performing 12 percent of the existing sources" or "the emission control that is achieved in practice by the best controlled similar source"). Congress did not intend MACT to be based on risk assessment or cost-benefit. However, to the extent that EPA could establish a more stringent MACT beyond the floor and may consider cost-benefit in doing so, the commenter offered several comments to improve the benefits analysis.

The commenter was concerned that EPA's earlier benefits analysis calculated costs relative only to reductions in emissions of fine particulate matter (PM2.5) and focused on only certain health effects. It did not include a comprehensive list of PM2.5-related health effects, nor did it cover health effects related to Hg, other HAPs, ozone, sulfur dioxide, nitrogen oxides or welfare effects related to Hg, PM, ozone, nitrogen and sulfate deposition. While they were pleased that EPA plans to expand its benefits analysis to include some of the health effects related to Hg, they did not believe it will go far enough. For example, the benefits analysis will include studies related to the effects of Hg exposure on IQ, but it will not adequately consider the

cardiovascular health effects. There are emerging data and well-developed studies showing an increase in death from heart attacks in men following Hg exposure. Furthermore, in considering IQ, EPA's analysis examines only decreased income resulting from lowered IQ and does not consider costs related to therapy, tutoring, special education and other remedial efforts.

Due to the commenter's concern that even the revised benefits analysis will underestimate the benefits of Hg reduction programs, they recommend that the benefits analysis be much more comprehensive and inclusive. Where quantitative data related to benefits are not available, the multiple benefits of additional Hg controls should be evaluated qualitatively and given weight in determining MACT limits that are more stringent than the MACT floor.

The commenter was concerned that the proposed definition of a hot spot indicates that the plant must cause exposures above the RID and believed this was inadequate. As suggested by the National Academy of Sciences panel that considered the health effects of MeHg, and further
supported by more recent research, the dose-response to Hg appears to be linear and effects have been reported at doses below the RID. It seems, therefore, that the definition of "hot spot" should not rely upon the RID.

Given the uncertainty that EPA has admitted relative to its modeling, the commenter felt the agency could not offer assurances about its calculations of the contributions of individual plants. When added to questions about health effects below the current RID, the commenter believed EPA's definition of hot spots in the proposal is inappropriate and does not protect public health.

Response:

EPA appreciates the input. Please see the RIA.

Comment:

One commenter (OAR-2002-0056-5422) noted that EPA has requested comments as to how reductions in population-level exposures of Hg will improve public health. The commenter stated that it was important to understand that there is a threshold for Hg levels in the blood below which there are no effects. This is in contrast to lead, which appears to have no clear threshold level. Unlike lead a significant (>50 percent) percentage of atmospheric Hg is from natural sources. Mercury has been present in fish tissue prior to the industrial revolution. EPA has selected an RfD for Hg in maternal blood (5.8 ppb) that serves as a de-facto threshold. This number, which is 10 times below the threshold number developed from the Faroe Islands study and 14 times lower than the WHO level of concern, is very conservative. If an unrealistically low threshold (ULT) for Hg blood levels were used to estimate benefits, reductions in blood levels between the true threshold and the ULT would create the appearance of a benefit where there is none.

EPA has requested comments as to the appropriateness of using IQ as an endpoint for both quantifying neurological development and the benefit analysis for reduced exposure to MeHg. In addition, EPA requested comments on the appropriateness of a linear dose response model evaluating health impacts. There is a concern that EPA may wish to develop a relationship between Hg emissions and general population IQ. If this relationship were then coupled with an imputed value for increased IQ for the general population, large estimated benefits could be generated that would not exist, since there is no evidence of IQ impact at blood Hg levels greater than the RfD but below the Faroe Island threshold level. There are opportunities to calculate an imputed value for IQ changes, for example, recent work by Jones and Schneider estimates that a 1 point increase in national IQ is associated with a 0.16 percent annual increase in GNP. There is also a concern that assuming a linear response between blood Hg and IQ would lead to an imputed benefit for reducing blood Hg below the threshold level, again creating benefits that do not exist.

EPA's successful lead reduction program is not an appropriate model for Hg. Lead is a pollutant that has been linked to neurological damage similar to that of Hg. In the late 1970s, EPA initiated a successful program designed to eliminate all lead emissions into the environment primarily through the phase-out of leaded gasoline. Since airborne lead emissions are linked to blood lead levels in children and related neurological impacts, it may appear reasonable to utilize the lead elimination model for dealing with Hg. However, there are important reasons why the program to reduce lead (total elimination of air emissions) is not appropriate for dealing with Hg.

- Virtually all airborne lead is attributed to anthropogenic sources while a large percentage of airborne Hg (>50 percent) is due to natural sources. It is impossible to eliminate all airborne Hg emissions.

- Lead emissions and ambient lead concentrations are primarily associated with urban areas while Hg emissions and ambient Hg concentration are global.

- While there appears to be no lower limit for neurological impacts for lead blood levels, Hg blood levels have a clear threshold below which there are no neurological impacts.

- While neurological impacts were clearly shown at blood lead levels present in urban US children in the 1970s, no such neurological impacts have been noted or documented at Hg blood levels currently found in American child-bearing age women or children.

Response:

EPA appreciates the input. Please see the RIA.

Comment:

One commenter (OAR-2002-0056-5477) stated that in its NODA, EPA notes that it had included a benefits assessment in its earlier proposed CAMR. The commenter would like to note

that EPA's benefits assessment was inadequate for the important issue of establishing "Beyond-the-floor MACT." EPA goes on to state that it has "preliminarily revised its proposed approach to analyzing the benefits associated with Hg emission reductions from power plants." In our earlier comments, the commenter did not propose a methodology for benefits assessment. Since then the commenter ha completed an extensive and comprehensive draft report "Estimating Reductions in U.S. Mercury Exposures from Decreased Power Plant Emissions and the Associated Economic Benefit," that is undergoing an intensive peer review. The extensive scientific work that forms the basis of this report was undertaken by the commenter with Harvard Center for Risk Analysis (HCRA), part of the Harvard School of Public Health (HSPH).

The report was prepared by Glenn Rice of HSPH as part of his doctoral work under the direction of Dr. James Hammitt, Director, Harvard Center for Risk Analysis. The report covers diverse areas of research, including: Hg emissions from sources, atmospheric transport and fate of Hg, atmospheric modeling and estimation of Hg deposition, relationship between Hg deposition and MeHg levels in fish (and how they change with changes in emissions), current and future exposures of humans to Hg in fish, dose response functions, and finally, the monetization of the benefits related to reduced Hg emissions from coal-fired power plants. The report evaluates these effects in four sequential tasks:

Task 1: Estimation of the effect of a specified reduction in power plant emissions of Hg on changes in regional Hg deposition and the resulting concentrations of MeHg in fish.

Task 2: Estimation of the effect of changes in MeHg concentrations in fish on human uptake.

Task 3: Estimation of the effect of changes in human uptake on the incidence of adverse human health effects.

Task 4: Quantification of the "monetized" value of the change in incidence of health effects.

Some of the benefits of controlling Hg are monetized for two Hg control scenarios. These are based on Clear Skies Initiative (CSI) Phase I, 2010 (26 TPY cap) and Phase II, 2020 (15 TPY cap). The Hg deposition levels for the base case (2001), as well as two pairs of base case/control case scenarios (Phase I and Phase II) were developed by the EPA using the REMSAD model as part of the Agency's analysis of the Clear Skies Initiative. The commenter's analysis estimated two sets of monetized benefits (for Scenario 1 and Scenario 2) which are based on comparing the control case and base case deposition levels for CSI Phase I and for Phase II. The Hg emission estimates for the base case as well as for four future scenarios were also provided by EPA, based on IPM outputs.

The commenter's analysis evaluated the effect of changes in Hg emissions assuming no changes in the population or dietary patterns of U.S. residents. For this reason, the results are best interpreted as an estimate of the benefits of lower Hg emissions in a steady-state world with

population and fish consumption patterns similar to current conditions. To estimate the benefits of reduced Hg emissions in future years would require projecting changes in human population, fish harvesting and consumption, the temporal relationship between changes in Hg emissions from power plants and levels of MeHg in fish, and other factors.

To account for the effects of changes in Hg deposition on MeHg levels in fish, the U.S. landmass was divided into five regions (West, Midwest, Mid Atlantic, Southeast, and Northeast). Additionally, the surrounding waters were studied as three regions for commercial and non commercial fish (Gulf, Atlantic, and "all other marine waters."). Estimates of human uptake of MeHg through fish consumption are based on regional patterns of consumption of fish species, both commercial and non-commercial.

The report integrates the avoided costs (or "benefits") for two endpoints associated with a reduction in the neurological effects that result from intrauterine MeHg exposures and with reductions in adult fatal and non-fatal cardiovascular (myocardial) events related to adult MeHg exposures. The effects of MeHg intake on myocardial events are less certain than the effects on neurological events. The neurological benefits were valued using a cost-of-illness model based on IQ-point gains that could result from decreased MeHg exposures. The non-fatal myocardial events were valued using a cost-of-illness approach. The premature mortality events were valued using a willingness-to-pay or value-of-statistical-life approach.

These neurological effects and the fatal and non-fatal cardiovascular effects likely account for a large fraction of the total monetary value of damage to humans that is associated with MeHg exposures. The study also discusses two additional effects that have been observed in children and associated with intrauterine MeHg exposures: increased blood pressure and decreased heart rate variability. However, the study does not quantify these risks, because the increased blood pressure does not appear to persist and the clinical significance of changes in heart rate variability of otherwise healthy children is not known.

Based on the preliminary results of the detailed analysis, benefits for Scenario 1 (26 TPY cap) associated with improved IQ range from $64 million (assuming a neurotoxicity threshold equal to the RfD) to $160 million (assuming no threshold). The corresponding benefits for Scenario 2 (15 TPY cap) are $93 million to $230 million. Much larger benefits are associated with avoided cardiovascular events (fatal and non-fatal). For Scenario 1, the monetized benefits are $2.7 billion. The corresponding benefits for Scenario 2 are $3.8 billion. All of these monetized benefits are per year. The total annual benefits for the two endpoints studied range from $2.8 billion for Scenario 1 to just over $4 billion for Scenario 2.

It is important to note that there is considerable uncertainty in the analysis and this includes a difference in the degree of confidence in the underlying studies for MeHg neurotoxicity (based on the various "islands" studies) and the studies related to effects of MeHg on the cardiovascular system. The neurological effects associated with in utero MeHg exposures are well documented and have been thoroughly evaluated by a number of research and advisory groups (e.g., National Research Council, 2000). However, the current published literature

providing evidence for evaluating the association between cardiovascular events with adult MeHg exposures is substantially smaller and more recent than that for the neurotoxic events.

It is also important to note that the commenter's study did not evaluate monetized benefits associated with EPA's proposed MACT approach under Section 112 or EPA's preferred approach of performance standards under Section 111 of the Clean Air Act or other more stringent and technologically feasible control levels (for example, less stringent of 90 percent control (from Hg in coal) or 0.6 lb/TBTU, as proposed by the States Stakeholders, (see Appendix A, Page 10-16, see OAR-2002-0056-5477) since EPA did not undertake modeling of these scenarios with IPM and REMSAD/CMAQ modeling. However, it should be obvious to EPA that monetized benefits would be substantially higher for the proposal offered by the States Stakeholders for only a small increase in costs (based on application of extremely cost-effective and commercially available technologies such as ACI). Thus, The commenter stood by their previous comments in support of a 90 percent reduction in Hg emissions from coal-fired EGUs.

Response:

EPA appreciates the commenters input. Due to the summary nature of the information provided, EPA was not able to fully evaluate the analysis and its inputs and therefore was not in a position to incorporate the analysis summary or conclusions.

Comment:

One commenter (OAR-2002-0056-5423) points out that, as shown in comment (O), EPA's premise for negative child neurodevelopment is based essentially on one endpoint from the Faroe Island study that is representative of exposure to a cocktail of toxic chemicals like PCBs, DDT and MeHg rather than MeHg alone as demanded by EPA's CAMR power plant emission controls. This commenter suggests that EPA's claim for health "benefits" from its CAMR is hypothetical or almost impossible to demonstrate because the suggested health concerns were drawn on either flawed or irrelevant epidemiological data.

In direct contrast to claims of health concerns from consuming fish with trace amounts of MeHg, this commenter offers findings from recent scientific studies supporting claims of significant children health-related benefits derived through adequate consumption of fish or fish oil containing omega-3 polyunsaturated fatty acids.

Helland et. al., (2003, Pediatrics, vol. 111, e39-e44) recently stated that:

> "Pregnant women [of Oslo, Norway] were recruited in week 18 of pregnancy to take 10 mL of cod liver oil [with about 2g of DHA+EPA] or corn oil until 3 months after delivery [in a randomized and double-blinded study]. Children who were born to mothers who had taken cod liver oil (n=48) during pregnancy and lactation scored higher [by 4 points] on the Mental Processing Composite of the K-ABC [Kaufman Assessment Battery for Children] at 4 years of age as

compared with children whose mothers had taken corn oil. This study indicates that maternal supplementation with very-long-chain n-3 PUFAs during pregnancy and lactation improves the intelligence of children at 4 years of age."

Daniels et al. (2004, Epidemiology, 15,394-402) found that:

> "Fish intake by mother during pregnancy and by the infant postnatally, was associated with higher mean [child] development scores [in a cohort of 7421 British children]. For example, the adjusted mean MacArthur [vocabulary] comprehension score for children [15 months old] whose mothers consumed fish four or more times per week was 72 compared with 68 among those whose mothers did not consume fish. Although total cord mercury levels increased with maternal fish intake, our data did not suggest adverse developmental effects associated with mercury. In a small study of subjects in [this] ALSPAC study, maternal DHA levels were associated with improved visual stereo acuity among offspring at 3.5 years of age. Fish intake during pregnancy has the potential to improve fetal development because it is a good source of iron and long chain omega fatty acids, which are necessary for proper development and function of the nervous system."

Finally, in another new study, Smuts et al. (2003, Obstetrics and Gynecology, vol. 101,469-479) explains:

> "[Our] study was a randomized, double-blind, controlled, clinical trial to determine the effects of increasing docosahexaenoic [DHA] acid intake during the third trimester of pregnancy on pregnancy and birth outcomes. Subjects were supplied with [DHA-] enriched eggs (mean of 133 mg of [DHA] per egg) or ordinary eggs (mean of 33 mg of [DHA] per egg). Eighty-three percent of subjects completed the study (291 of 350 enrolled). No subject was discontinued for an adverse event. No safety concerns were raised by the study. The current study found a 6-day longer period of gestation when [DHA] intake was increased ... Olsen et al. suggested that higher [DHA+EPA] intake from fish by Faroe Islanders compared with Danes was the reason for longer gestation in Faroe Islanders. The authors subsequently demonstrated increases in gestation of 4 and 8.5 days, respectively, in randomized clinical trials that provided 2.7 g per day of [DHA+EPA] to a group of healthy pregnant women and to healthy pregnant women with a previous pre-term delivery."

The commenter notes that claims of concern for fetal and child health by EPA and Hg activists appear disingenuous because they largely failed to emphasize to the public the benefits of fish consumption. This activism could unnecessarily terrorize expectant mothers into not eating a food that promotes better fetal development and child health.

Premature birth is a striking example. So serious is this outcome that the March of

Dimes organization has adopted it as a primary cause. More than 470,000 babies are born prematurely every year in the U.S. These infants aren't just small; they're developmentally "unfinished."

The March of Dimes provides these facts on prematurely born babies:

- Has increased by 29 percent since 1981
- Accounts for 12 percent of all live births
- Can happen to any pregnant woman
- Is the leading killer of babies in their first month of life
- Is a major cause of long-term health problems, including cerebral palsy, mental retardation, blindness, chronic lung problems, Respiratory distress syndrome and bleeding in the brain
- Is the number one obstetrical problem in the country
- Robs families of the full potential of their children, society of their future leaders and our nation of strong and healthy citizens
- Places tremendous financial burdens on everyone. Hospital charges for infants with a principle diagnosis of prematurely average $75,000, and add up to billions of dollars each year.

Recognizing the role of fish nutrition plays in helping prevent the tragedy of premature births, the March of Dimes is funding a Danish and Chinese research team to further clarify the issue. One of the researchers, Dr. Sjurdur Olsen of Denmark reported that Danish women who consumed fish or seafood at least once a week during the first 16 weeks of pregnancy have three times less risk of low-birth weight or premature births. But a closer look at the literature will reveal ample evidence already available that women who avoid fish in their diets during pregnancy are at increased risk for delivering their babies early, which increases risk for their babies being born small, sick and dying.

Response:

The US Government emphasizes that fish and shellfish are an important part of a healthy diet for women and young children; and that women and young children should include fish or shellfish in their diets due to the many nutritional benefits. Recommendations for selecting and eating fish or shellfish are made by EPA and FDA. These recommendations, if followed, should enable women and young children to receive the benefits of eating fish and shellfish and, at the same time, they can be confident that they have minimized their exposure to the harmful effects of mercury.

Comment:

One commenter (OAR-2002-0056-5423) notes that the postulated but unconfirmed effects of MeHg on cardiovascular health in the NRC (2000) report appear to have contributed to EPA's RfD for MeHg.

Alan Stern, of the New Jersey Department of Environmental Protection and member of the NRC (2000) MeHg committee, recently revealed:

> "In 2000, the National Research Council's Committee on the Toxicological Effects of Methylmercury issued a report (NRC, 2000) in which it considered the various adverse health effects associated with the exposure to methylmercury (MeHg). Among the effects considered were cardiovascular effects. The committee concluded that 'Given the limits of the available data, neurotoxicity is the most sensitive, well-documented health endpoints. However, there is emerging evidence of potential effects on both the immune and cardiovascular systems at low doses of exposure. Although these effects are not well understood, emerging data underscore the need for continued research and raise the possibility of adverse effects ... at or below the current levels of concern for developmental neurotoxicity.' The committee recommended that an overall uncertainty factor of adjustment of 10 be applied to the neurodevelopmental point of departure to derive a MeHg reference dose (RfD). This uncertainty factor, in part, addressed the possibility that cardiovascular effects may ultimately prove to be a more sensitive endpoint than neurodevelopment effects. The US EPA, in its derivation of an RfD for methylmercury, followed the lead of the NRC committee in applying a similar rationale for its 10-fold uncertainty factor adjustment (US EPA 2004)."

The commenter suggests that EPA should be more critical in providing an independent assessment on this potentially dangerous and poorly documented claim. To that end, the commenter offers several concise criticisms on the two main published studies (as cited by EPA's NODA) suggesting a connection between MeHg exposure from fish and cardiovascular disease (CVD), coronary health disease (CHD) and even death in adults. (A longer and more thorough review on this recent alarmism about the negative impacts of fish intake on cardiac health can be found in "Fish, Mercury and Cardiac Health" by CSPP.) But it should be pointed out that the third study cited by the EPA's NODA, the Yoshizawa et al. (2002, New England Journal of Medicine, vol. 347, 1755-1760) paper, actually reported their inability to confirm an association of total Hg exposure and risk of CVD based on a 5-year follow-up of 33,737 U.S. male health professionals. The results of Yoshizawa et al. (2002) clearly did not raise the "possibility that MeHg in fish can reduce the cardio-protective effects of fish consumption in adult males" as incorrectly implied by EPA's citation.

First, the commenter provides some background on the two studies claiming negative cardiac health associations with fish consumption.

(1) The Finnish Study by Salonen et al. (1995, Circulation, vol. 91,645-655; 2000, Atherosclerosis, vol. 148,265-273) and Virtanen et. al., (2002, poster presentation in the April 23-26, 2002 American Heart Association, Asia Pacific Scientific Forum at Honolulu, Hawaii): A study of 2005 men from Kuopio, eastern Finland found that men in the highest quarter (>2.5 ppm) had a 1.6-fold risk of CVD death and 1.7-fold risk of CHD death when compared to men in

the lowest three quarters after adjusting for numerous risk factors including age, LDL (bad) cholesterol and triglyceride, intakes of saturated animal fatty acids and etc.

(2) The European/Israeli Study by Guallar et. al., (2002, New England Journal of Medicine, vol. 347, 1747-1754): A case-control study of 684 men with 724 controls reported increasing toe nail Hg level from 0.11 to 0.66 ppm (about 0.34-2 ppm in equivalent hair Hg levels) is associated with a doubling of the risk of myocardial infarction after adjusting for numerous risk factors like age, family history of heart attack, smoking status, alcohol intake, diabetes, history of hypertension, selenium intake, etc.

However, as explained in the commenter's report, "Fish, Mercury and Cardiac Health," numerous risk factors other than MeHg in fish will more likely explain most of the findings in Salonen et. al., (1995, 2000) and Guallar et. al., (2002).

Statistics of mortality from Coronary Heart Disease: Men of Eastern Finland are especially vulnerable

"The intake of diary products, potatoes, butter, and sugar products was very high in Finland. A similar but lower intake pattern was observed in The Netherlands. Fruit, meat and pastry consumption was high in the USA. Cereals and wine consumption was high in Italy, while bread consumption was high in Yugoslavia with the exception of the Belgrade cohort. In Greece, the intake of olive oil and fruit was very high, while the Japanese cohorts were characterized by a high consumption of fish, rice, and soy products."

Table 1: Age-standardized 25-year death rates per 1000 from CHD in 16 cohorts of the Seven Countries Study. Standard error of rate in parenthesis.

Cohorts	N	CHD (death rates/1,OOO)
US Railroad, USA	2571	160 (7)
East Finland, Finland	817	268 (15)
West Finland, Finland	860	180 (13)
Zutphen, The Netherlands	878	169 (13)
Crevalcore, Italy	993	93 (9)
Montegiorgio, Italy	719	60 (9)
Rome Railroad, Italy	768	87 (10)
Dalmatia, Croatia	671	54 (9)
Crete, Greece	686	25 (6)

Cohorts	N	CHD (death rates/1,OOO)
Corfu, Greece	529	48 (9)
Tanushimaru, Japan	508	30 (8)
Ushibuka, Japan	502	36 (8)
Velika Krsna, Serbia	511	43 (9)
Zrenjanin, Serbia	516	116 (14)
Belgrade, Serbia	536	106 (13)
Slavonia, Croatia	696	89 (10)

Menotti et al., 1999, European Journal of Epidemiology, vol. 15, 507-515

The commenter's criticisms on Salonen et. al., (1995, 2000) include the following points:

(1) Salonen et. al., (1995) own admission: "Theoretically, our findings could be specific only for men in Eastern Finland, who traditionally have a high intake of meat, fish, and saturated animal fat and a low intake of selenium and vitamin C and, most likely, other vegetable-derived antioxidants."

(2) The Kupio population has one of the highest recorded rates of CHD and high consumption of animal fat with high measured levels of LDL (bad) cholesterol.

(3) Stern (2005, Environmental Research, in press) pointed out that even in Salonen et al. (1995) as long as 9 years already elapsed between the collection of hair and urine samples and the recording of a CVD and CHD and death event. Updated report of KIHD Hg-related results in Virtanen et. al., (2002) extends the elapse time to 16 years or so and hence contributing to a serious potential misclassification of causes and effects.

(4) Clarkson (2002) noted that highest recorded hair level is 15.7 ppm and more than 6 standard deviations from the mean and only a small percentage of the population has high hair Hg. Yet high-value points may playa major role in this type of study, "it would have been of interest to see if these correlations persisted when the very high mercury levels were excluded."

(5) No clear accounting for stress–which is believed to be a major risk factor.

The commenter's criticisms on Guallar et. al., (2002) include the following points:

(1) Contradicted by the negative results of Yoshizawa et al. (2002) 5-year follow-up study of 33.737 US male health professionals that covers a wider range of toenail Hg from 0 to 14.6 ppm (or about 45 ppm in equivalent hair Hg level)

(2) Why is LDL cholesterol not measured and identified as a risk factor (while HDL and total cholesterol were measured)?

(3) Serious challenges and questions from Plante and Babo (2003) in New England Journal of Medicine (vol. 348, 2151-2152): "Patients with Minamata disease and hair mercury levels above 100 ppm did not have a higher rate of death from heart disease than controls, nor did they have a higher degree of arteriosclerosis. In the Minamata region of Japan, a population of approximately 50,000 with an average hair mercury level of 50 ppm did not have a higher rate of death from heart disease than a reference population of 800,000 with an average level of 9 ppm. Cree Indians with an average hair mercury concentration of 10 ppm have a lower risk of death from circulatory disease than the rest of the population in Quebec, in which the average hair mercury level is 0.5 ppm. If, as Guallar et. al., suggest, mercury increases the risk of myocardial infarction by more than 100 percent when the hair mercury level reaches 2 ppm, how can one explain the absence of effects at doses greater than 100 ppm?"

Concerning "sudden death" the clinical evidence continues that fish nutrition can lower the risk:

> "The n-3 fatty acids found in fish are strongly associated with a reduced risk of sudden death among men without evidence of prior cardiovascular disease. As compared with men with levels of long-chain n-3 fatty acids in the lowest quartile, those with levels in the highest quartile had an 81 percent lower risk of sudden death." (Albert et. al., 2002)

> "[W]e have summarized the growing clinical evidence that these n-3 fatty acids are antiarrhythmic and can prevent sudden cardiac death in humans. These n-3 fatty acids have been part of the human diet for some 2 to 4 million years. They are safe and have been listed on the GRAS ('generally regarded as safe') list according to the Food and Drug Administration in amounts up to 3.5 g of fish oil per day." (Leaf et. al., 2003)

> "Alexander Leaf and colleagues suggest a hypothesized cellular mechanism through which 3 PUFAs affect ion channels to reduce the risk of arrhythmia. The messages ... are clear. For clinicians, it is time to implement the current American Heart Association dietary guidelines that recommend the dietary intake of 1 to 2 fish meals, particularly fatty fish, each week. For policymakers, there is a need to consider new indication for treatment with low-dose n-3 PUFAs supplements ..." (Siscovick et. al., 2003)

Speaking on cardiac risk concerns, Professor Tom Clarkson, Distinguished Professor of Environmental Medicine at the University of Rochester has commented that:

> "Eating lots of ocean fish isn't much of a hazard compared to missing out on the benefits from not eating fish. A slew of scientific reports have shown that eating fish helps protect against cardiovascular disease and enhances brain development

before and after birth. Fish is a rich source of low-fat protein and is full of fatty acids known to lower cholesterol. Overstating the almost negligible risk of mercury could adversely affect millions of people who face the risk of heart disease."

Dr. Eric Rimm, Professor of Epidemiology and Nutrition at Harvard School of Public Health agreed:

"The message of fish being good has been lost and people are learning more about the hypothetical scare of a contaminant than they are of the well documented benefits of coronary disease reduction. The danger of the tuna fish is not well documented compared to the potential dangers for a 50-year-old male or female who are at a much higher risk of coronary health."

Response:

EPA acknowledges that there are complexities, including a variety of potential confounders, that must be considered in relation to potential cardiovascular mortality linked to methylmercury exposure. For additional discussion of this endpoint, see Appendix D and Appendix B of RIA for this rule.

Comment:

One commenter (OAR-2002-0056-5423) presents Figure O1 to show the rarely seen "evidence" that both EPA and the "NAS review" in 2000 (see more criticisms of the "NAS" [actually NRC (2000)] review under comment P below) had adopted to support their claims of negative neurodevelopmental impacts from prenatal exposure to MeHg through maternal consumption. The result was drawn from the Faroe Island children study originally published by Grandjean et al. (1997, Neurotoxicology and Teratology, vol. 19, 417-428) and the particular endpoint test (see additional criticisms by CSPP in comment Q below) is the so-called cued Boston Naming Test (note that this is not to be equated to "IQ" as represented in the final section of EPA's NODA).

The commenter points out that Figure O1 clearly suggests a significant scatter in the test scores as MeHg exposure level changes. It is also worth reminding that this particular endpoint is indeed the best evidence allowing the EPA and "NAS" suggestions of negative impacts with increasing MeHg exposure–as guided by various statistical fitting lines in Figure O1 despite the large scatter. More important to note in Figure O1 is the relative position of the EPA adopted level of MeHg RfD in the equivalent blood Hg levels of 5.8 ppb (marked as red dashed vertical line in Figure 01). The superposition of the EPA's adopted MeHg RfD shows a clear disconnect to the underlying data which forms the original claim for negative impacts linked to MeHg exposures. The commenter believes that this result makes clear the distinction between the actual levels of harm or concern for MeHg and the hypothetical and ultra-precautionary level of safety set by EPA's RfD shown in Figure L1 above.

The commenter notes that there are even more serious issues in the underlying epidemiological data from the Faroe Island children study which exposes its selection for an RfD level as highly inappropriate. Not the least of which is the refusal of the Faroe Islands researchers to release their raw data to allow independent statistical analyses violates EPA's own data quality guidelines.

The MeHg exposure profile for the Faroe Island study is neither compatible nor directly applicable to U.S. fish consumers. By admissions of the original Faroe Island study researchers (mainly Dr. Philippe Grandjean and Dr. Pal Weihe) and several published scientific evaluations of the Faroe Island study, the Faroe Island results should best be considered as a study assessing exposures to a mixture of chemicals like PCBs, DDT and MeHg rather than MeHg alone. It has long been noted and admitted that the Faroe Island study cohorts were contaminated by maternal exposure to high levels of DDT and PCBs via consumption of pilot whale meat and fat. The PCBs levels were evaluated to be about 600 times the so-called Aroclor 1254 RfD level established by EPA's own Integrated Risk Information System (Dourson et al., 2001, Neurotoxicology, vol. 22, 677-689).

In addition, the commenter states that it should not go unnoticed that in a letter to the EPA, Drs. Kenneth Poirer and Michael Dourson, both as former EPA's RfD/Reference Concentration Work Group co-chairs, had previously provided their scientific findings to the Technical Information Staff at EPA, advising that: "The Faeroe Island studies are not the proper choice for the critical study for a methylmercury RfD." EPA continues to ignore this and more recent scientific evaluations.

Finally, in a February 9, 2004 open letter there is the crucial clarification by Faroe Island Children Study's Chief Physician, Dr. Pal Weihe, that the Faroese children are exposed to Hg by consumption of pilot whale meat only, not fish. In contrast, says Dr. Weihe, the fish consumption most likely is beneficial to their health. Dr. Weihe's letter follows:

> To whom it may concern:
>
> Faroe Islands women do not eat Hg-tainted fish and fish consumption does not harm Faroese children.
>
> In the Boston Herald, Friday, February 6, 2004, p. 20 the following was stated about a Hg study in the Faroe Islands conducted in the cooperation with the Harvard University: "A fish industry spokesman said that the Harvard study was flawed because Faroe Islands women typically eat far more mercury-tainted fish than do Americans."
>
> As the researcher in charge of the Hg studies on children in the Faroe Islands since 1985 I want to correct this statement. The Faroese children are not exposed to methylmercury by eating fish. They are exposed to Hg by the traditional consumption of pilot whale meat. Fish normally consumed in the Faroes, e.g.

Cod and haddock, are low in Hg and do not, to my opinion constitute any threat to the health of the Faroese children. In the contrary the fish consumption most likely is beneficial to their health.

The Faroese authorities in 1998 recommended women who plan to become pregnant within months, pregnant women, and nursing women to abstain from eating pilot whale meat. The Hg concentration in the blood of pregnant women has declined dramatically since and are now below the US-EPA limit.

Yours sincerely,
Pal Weihe, Chief Physician

The commenter asks, how can EPA or the National Research Council seriously cling to the Faroe study for its RfD for fish consumption when the lead author states the study has nothing to do with MeHg in fish, but only in whale meat? How can Dr. Grandjean claim associations between IQ levels in Faroese children and fish consumption (see further discussion under comment Q below) when Dr. Weihe reports that those children (a) are not exposed to MeHg by eating fish, (b) are exposed to no health threat from fish, and (c) actually benefit from maternal fish consumption?

The commenter urges EPA to discontinue relying on the very weak (and inappropriate) scientific foundation to base its claim of negative impacts on children neurodevelopments using the results of the inferior Faroe children study.

The commenter further documents here additional evidence of the extremism or ultra-precautionary nature of the current EPA RfD for MeHg.

First, it is clear from the ethical guidelines established by the Institutional Review Board of the National Center for Health Statistics of the CDC that approved the NHANES study that cautions are issued to NHANES participants only if their total hair Hg levels are above 15 ppm or total blood Hg above 200 ppb (McDowell et. al., 2004, Environmental Health Perspectives, in press, available online May 27, 2004). The ultra-precaution by EPA is connected to its RfD which considers a blood Hg level to be safe only at levels below 5.8 ppb, which is dramatically lower than the ethical guideline established by the Institutional Review Board of CDC.

Second, it is obvious from the latest results of the Japanese hair Hg measurements for 8665 individuals collected in 10 different locations over 1999 to 2002 by Yasutake et al. (2004, Journal of Health Science, vol. 50 (2), 120-125) that the overwhelming majority of the Japanese population, i.e., 87 percent, has hair mercury levels exceeding the mercury" safety" level set by EPA's RfD. Since there is no detectable epidemics of any defective mental capability of both the Japanese adult and children populations, the commenter suggested that such reality confirms the ultra-precautionary nature of the current EPA RfD level for MeHg, and conclude that the actual levels of concern from MeHg exposure occurs at much higher levels (see for example, various values identified in Figure L1) than an the RfD value of 5.8 ppb in blood Hg adopted by

EPA.

Response:

EPA acknowledges that there are complexities, including a variety of potential confounders, that must be considered in relation to potential cardiovascular mortality linked to methylmercury exposure. For additional discussion of this endpoint, see Appendix D.

Comment:

One commenter (OAR-2002-0056-5423) believes that this particular statement by EPA is both confusing and misleading. The statement all by itself appears contradictory to what was stated in comment (O) that EPA's RfD was derived from a single neurodevelopmental endpoint.

In addition, the commenter believes that any reference to the NRC (2000) report, Toxicological Effects of Methylmercury, about the review and assessment of these three epidemiological studies would be more complete in noting that:

> "The committee concludes that there do not appear to be any serious flaws in the design and conduct of the Seychelles, Faroe Islands, and New Zealand studies that would preclude their use in a risk assessment. However, because there is a large body of scientific evidence showing adverse neurodevelopmental effects [unfortunately, the NRC did not provide any precise citation for such evidence] ... the committee concludes that an RfD should not be derived from a study, such as the Seychelles study, that did not observe an association with MeHg." (p. 6)

Therefore, the commenter concludes that the high-quality results from the Seychelles study (with additional assessment noted below) were ignored by NRC (2000) not for any scientifically defensible reasons, but because of a direct bias to recommend only results that show evidence for "adverse neurodevelopmental effects." This situation is truly unfortunate because it is relatively well-known that the results of the Faroe Island study had been contaminated by simultaneous exposures to other toxic chemicals like PCBs and DDT.

A post NRC (2000) analysis by Dourson et al. (2001, Neurotoxicology, vol. 22, 677-689) recommended that "The Faroe Islands data are from exposures to a mixture of chemicals. The Seychelles Island data are from exposures to primarily one chemical, MeHg.... We would... encourage EPA to use the Seychelles Island data as the basis of its MeHg RfD."

The commenter believes that this is why it is scientifically appropriate to challenge the biased conclusions of NRC (2000) and hence EPA's basis for its MeHg RfD. The Seychelles Island results are clearly superior for deriving RfD exposure to MeHg for the U.S. population. This is so simply because that study is without toxic confounders and the Seychelles Island mothers consumed ocean fish containing MeHg concentrations comparable to those consumed by the general U.S. population.

In contrast to the Faroe Island study, the Seychelles Child Development Study (SCDS), "was specifically designed to test the validity of [the] hypothesis [of adverse neurodevelopmental effects] in a well-nourished population exposed to MeHg only from high consumption of unpolluted ocean fish." The research authors recently concluded:

> "[SCDS] longitudinal assessment at 9 years of age indicates no detectable adverse effects in a population consuming large quantities of a wide variety of ocean fish. These results are consistent with our earlier findings in the same children examined at 6, 19, 29 and 66 months of age. In Seychelles, fetal exposure was continuous through frequent consumption of ocean fish containing concentrations of MeHg comparable to those consumed by the general population in the USA. We recorded effects from covariates known to affect child development, but did not find an association with prenatal mercury" (p. 1692 of Myers et al., 2003, The Lancet, vol. 361, 1686-1692).

Constantine Lyketsos of the John Hopkins Hospital (2003, Lancet, vol. 361, p. 1668) in offering a professional overview on the implications of the Seychelles study concluded:

> "On balance, the existing evidence suggests that methyl mercury exposure from fish consumption during pregnancy, of the level seen in most parts of the world, does not have measurable cognitive or behavioral effects in later childhood. This conclusion is especially true against the background of the several other variables that affect cognitive-behavioral development. The positive findings from the Faeroe Islands and New Zealand studies may be related to the fact that pilot-whale blubber and shark muscle contain 5-7 times the concentrations of methyl mercury than the fish consumed in the Seychelles. While higher concentrations in seafood do not necessarily lead to higher levels in maternal hair, consumption of much larger boluses by the mother could lead to greater difficulty on the part of the developing fetus to detoxify the mercury by natural mechanisms, as Meyers and colleagues propose. Whatever the answer, the discrepant findings from the various studies need explaining. Whilst there is always an issue of power to detect an effect in a study reporting null findings, this is not likely to be the case in the Seychelles study with the sample size involved. If there is subtle association that could only have been detected in a much larger sample or through the use of more sensitive tests, it can reasonably be argued that the effect would be small enough to be essentially meaningless from the practical point of view. For now, there is no reason for pregnant women to reduce fish consumption below current levels, which are probably safe."

Response:

In deriving the reference dose for methylmercury, EPA relied on an integrated analysis involving three studies. These longitudinal, developmental studies were conducted in the Seychelles Islands, the Faroe Islands, and New Zealand. The Seychelles study yielded scant

evidence of impairment related to in utero methylmercury exposure, whereas the other two studies found dose-related effects on a number of neuropsychological endpoints. In the assessment developed for the RfD, emphasis is placed on the results of the Faroe Islands study, the larger of the two studies that identified methylmercury-related developmental neurotoxicity. Supporting evidence from the New Zealand study provides assurance that choosing this focus is the appropriate strategy for protecting public health. Conclusions from the National Research Council review of methylmercury support this use of the Faroes Island study and disagree with the suggestion of a role for PCBs in the neurological effects observed (NRC. 2000. Toxicological Effects of Methylmercury. National Academy Press.), saying that

> *"The committee concludes that there do not appear to be any serious flaws in the design and conduct of the Seychelles Islands, Faroe Islands, and New Zealand studies that would preclude their use in a risk assessment."*

The Agency's derivation of the RfD also followed the National Research Council recommendation for an overall composite uncertainty factor of no less than 10.

In summary, the Agency's overall confidence in this RfD assessment is high. Three high-quality epidemiological studies published since the last derivation of the oral RfD in 1995, have been included in the analysis. Two of the studies (Faroe Islands, New Zealand) reported effects on a number of neuropsychological endpoints, whereas the third (Seychelles Islands) reported no effects related to in utero exposure to methylmercury. Benchmark dose analysis of a number of endpoints from both the New Zealand and Faroe Islands study converged on an RfD of 0.1 μg/kg-day, as did the integrative analysis combining all three studies. Although there was coexposure to PCBs in the Faroe Islands study, statistical analysis indicated that the effects of PCBs and methylmercury were independent. Moreover, benchmark dose analysis of the endpoints that were significantly associated with methylmercury yielded RfDs that were approximately the same when corrected for PCBs. The same was true when the analysis was or based on the subset of the cohort in the lowest tertile with respect to PCB levels, as compared with the full cohort. These findings provide further evidence that the identified effects are in fact the result of methylmercury exposure.

Comment:

One commenter (OAR-2002-0056-5423) notes that the primary author the Faroe Island study, Dr. Philippe Grandjean, was found to have admitted in the May 20, 2002 Mercury Forum held at Mobile, Alabama (http://www.masgc.org/mercury/) that "In conclusion, the commenter had obtained evidence of subtle adverse effects on neurobehavioral functions, blood pressure, and growth. At age 7 years, a doubling of the Hg exposure corresponds to a developmental delay of up to 2 months. Although IQ tests were not done, such delays would be comparable to a loss of about 1.5 IQ points."

Another relevant notice is the statement in Dr. Grandjean's written testimony at the Mercury MACT Rule Hearing at Maine State House on March 1, 2004, that "Even though the children that the commenter examined were all basically normal, we have documented detectable

deficits that appear to be permanent." CSPP takes the statement to suggest that Faroese children are essentially all normal with normal functioning capability despite the permanent "detectable deficits" of the sort described by Grandjean.

Finally, it was also clear that the cued Boston Naming Test conducted by the Faroe study does not constitute a proper IQ test.

The commenter believes that, in short, Dr. Grandjean's statements are contradictory at best. They would not hold up in a rigorous scientific evaluation by other experts or his peers. They should not go unchallenged by EPA either, especially as his raw data are not transparent.

But the commenter notes that the really relevant question to assessing the statement in (Q) is whether if any or all of these reputed neurodevelopmental outcomes and tests can be shown to be related to MeHg exposure. In that regard, it is important to consider that for a total 17 neuropsychological tests conducted by the Faroe study to search for associations with prenatal exposure to MeHg, only 3 tests (both the cured and uncured Boston Naming Tests and the so-called Neurobehavioral Evaluation System Continuous Performance Test) yielded statistically significant correlations *only if* the Faroe researcher considers maternal cord blood as an independent predictor (Budd-Jorgensen et. al., 2003, Environmetrics, vol. 14, 105-120). The statistical correlation for the same 3 test scores dramatically turned insignificant or only marginally significant when the measured maternal hair Hg is adopted as the independent variable instead.

Dr. Gary Myers, one of the main authors of the Seychelles Island Child Development Study, makes the point that even the 3 statistical associations found by the Faroe Island study are a lot less impressive than one is lead to think if one properly weighs in the statistical odds. In a July 29, 2003's testimony to the Senate Environment and Public Work Committee, Myers noted:

> "Through 107 months (9 years) and over 57 primary endpoints, the [Seychelles Island] study has found only three statistical associations with prenatal MeHg exposure. One of these associations was adverse, one was beneficial and one was indeterminate. These results might be expected to occur by chance and do not support the hypothesis that adverse developmental effects result from prenatal MeHg exposure in the range commonly achieved by consuming large amounts of fish. The test results do show associations with factors known to affect child development such as maternal IQ and home environment so there is evidence that the tests are functioning well [i.e., the Seychelles Island Child Development Study shows evidence for a high degree of internal consistency]."

Myer concluded in his senate testimony:

> "We do not believe that there is presently good scientific evidence that moderate fish consumption is harmful to the fetus. However, fish is an important source of protein in many countries and large numbers of mothers around the world rely on

fish for proper nutrition. Good maternal nutrition is essential to the baby's health. Additionally, there is increasing evidence that the nutrients in fish are important for brain development and perhaps for cardiac and brain function in older individuals."

The commenter believes that in the context of positive or negative brain development from trace-Hg fish consumption, real world data trumps modeling or alarmist assertions. For example, in the latest data from the Trends in International Mathematics and Science Study, students (grade 4 and 8) in Asia continued to excel. Singapore, Hong Kong, Japan and Korea were among the top performers in over 50 countries participating. The U.S. placed well below these countries. As EPA noted, Asians are among the largest fish consuming peoples in the world. If alarming neuropsychological and neurodevelopmental deficits from prenatal MeHg exposure through fish consumption (as interpreted by Dr. Grandjean in the Faroe children study) are correct, then these Asian students are the very populations that should be evidencing an epidemic in low IQ, instead of topping the curve on international standardized math and science tests.

Response:

As many factors influence performance, relative rankings on the International Mathematics and Science Study are not indicative of the impact of MeHG. As stated above, in deriving the reference dose for methylmercury, EPA relied on an integrated analysis involving three studies. These longitudinal, developmental studies were conducted in the Seychelles Islands, the Faroe Islands, and New Zealand. The Agency's overall confidence in this RfD assessment is high. The US Government also emphasizes that fish and shellfish are an important part of a healthy diet for women and young children; and that women and young children should include fish or shellfish in their diets due to the many nutritional benefits. Recommendations for selecting and eating fish or shellfish are made by EPA and FDA. These recommendations, if followed, should enable women and young children to receive the benefits of eating fish and shellfish and, at the same time, they can be confident that they have minimized their exposure to the harmful effects of mercury.

Comment:

The commenter (OAR-2002-0056-5460) stated that in response to EPA's request for feedback on the comments submitted by the Electric Power Research Institute ("PERI") and the UARG (see 69 Fed. Reg. at 69,873 [2nd Column]), the commenter noted that those comments suffer from profound factual, logical and legal flaws. The commenter further stated that, accordingly, EPA need not attempt to respond to every last technical assertion advanced by those commenters. The commenter added that listed below are two illustrative examples of threshold, overarching problems in the PERI and UARG comments.

The commenter stated that, first, in a strained attempt to argue that domestic power plants do not contribute to Hg hot spots, PERI writes that a particular "geographic location" is

"utility-influenced" only if 50 percent or more of the Hg depositing there stems from utilities (See OAR-2002-0056-2578 ["PERI Comments"]). But, the commenter stated, PERI provides no reason to adopt its definition of "utility-influenced" and no such reason exists. The commenter added that, plainly, utilities can contribute less than 50 percent of the Hg in a given location and still influence that location. See, e.g., William L. Prosser, W. Page Keeton, et al., The Law of Torts § 52 (5th ed. 1984) ("Pollution of a stream to even a slight extent becomes unreasonable when similar pollution by others makes the condition of the stream approach the danger point."); U.S. v. Alcan Aluminum Corp., 315 F.3d 179, 187 (2d Cir. 2003) (explaining that harm that is minimal on its own may be significant when combined with other harms). The commenter stated that, in addition, EPRI's argument that domestic power plants do not cause hot spots cannot be reconciled with its simultaneous assertion that the "state-of-the-science is too imprecise" to measure the significance of reduced Hg emissions (see also OAR-2002-0056-2922 (UARG Comments)). The commenter further stated that PERI is simultaneously claiming that EPA cannot measure the consequences of reducing Hg emissions and that power plants are only a small part of the Hg problem. The commenter stated that PERI cannot have it both ways: Either the significance of power plant emissions can be measured with precision, or it cannot be. The commenter stated that , in all events, however, EPA has already determined that Hg power plant emissions require regulation pursuant to Section 112, and no factual or legal basis exists to undo that decision now.

Response:

EPA has examined the commenter's concerns in context of the final rulemaking. EPA is finalizing a cap-and-trade approach under section 111. EPA has addressed the hot spots issue in the Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units and the Removal of Coal- and Oil-fired Electric Utility Steam Generating Units from the Section 112(c) List for a discussion of the Agency's rationale for not proceeding under Section 112 Notice and in the Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls in the docket.

Comment:

The commenter (OAR-2002-0056-5460) states that with regard to step five of EPA's proposed revised benefits assessment methodology, EPA has not adequately explained several aspects of its focus on IQ as the neurodevelopmental endpoint. See 69 Fed. Reg. at 69,878. The commenter further stated that, for example, EPA has not adequately explained why it is not also evaluating other neurodevelopmental endpoints. The commenter added that it has likewise failed to explain how it will use the Faroe Islands and Seychelles Islands studies to measure IQ decrements, especially given its admission that those studies did not conduct sufficient tests to estimate IQ.

Response:

As part of its analysis of the final rule, EPA has estimated some of the health benefits of reducing Hg from utilities. At this time EPA is only able to provide quantative estimates of the benefits of reducing neurological impacts of exposure to MeHg for a portion of the U.S. population. Please refer to Chapter 2 of the RIA for a description of approach and rationale.

Comment:

One commenter (OAR-2002-0056-5497) stated that the NODA indicated that an analysis currently being performed by EPA and Harvard researchers will be peer-reviewed and placed in the docket "as soon as it is available." The commenter questions whether EPA can even complete the detailed analysis described in Step 5 by March 15, 2005 – the date on which EPA says it will issue a final CAMR – much less having it peer reviewed. The commenter further doubts whether interested parties will have a meaningful opportunity to review and comment on this analysis before a final rule is issued. This lack of a meaningful comment opportunity is of particular concern because this last-minute analysis appears to be designed to overstate whatever health effects may result from Hg emissions from coal-fired power plants.

The commenter asked why was this detailed health effects assessment not included as part of the Hg or utility studies? Why was it not presented as part of the proposed rulemaking package? A number of questions in this part of the NODA involve human health assumptions and approaches that are significantly different than those recommended by the National Academy of Science (NAS) and those used by EPA in establishing a Reference Dose (RID) for MeHg. Why were those new approaches not vetted as part of the Integrated Risk Information System (IRIS) database process or in some broader forum?

The commenter's earlier comments contained a series of criticisms about EPA's RID process. Those comments expressed concerns about how EPA had manipulated assumptions to produce a reference dose that was lower than ones produced by other federal or international organizations. Many of the questions posed by EPA in the NODA seem aimed at further manipulating available information to find even lower levels of cause and effect relationships.

Question a: The focus of neurodevelopmental health of children

The neurodevelopmental health of children should remain the focus of MeHg health effects. Other health endpoints such as cardiovascular effects should not be used in place of neurodevelopmental effects on children. The cardiovascular studies cited by EPA and other commenters raise many scientific questions. The cardiovascular studies have yielded, contradictory results. The Finnish study by Salonen that first raised concerns about the linkage between MeHg exposure and cardiovascular disease has many problems. These problems are discussed in detail in EPRI's NODA comments and comments submitted by the Center for Science and Public Policy. Briefly, Salonen's conclusions rest on relative risk relationships that are so low as to be questionable whether they really exist. In addition, coronary heart disease has multiple risk factors that cannot be completely controlled in a study design–the eastern

Finland study group had high intake of meat, fish and saturated animal fat and a low intake of vitamins and other vegetable-derived antioxidants. Finally, follow-up studies of this Finnish population were greatly separated in time, casting further doubts on Salonen's findings.

The ongoing National Health and Nutrition Examination Study ("NHANES") study has failed to find a relationship between blood Hg concentrations and blood pressure, raising further questions about the relationship between MeHg exposures and cardiovascular disease. Therefore, the focus of any benefits analysis should remain on the neurodevelopmental health of children, until other health endpoints have been studied to the extent of the neurodevelopmental ones and those other endpoints are shown to be more sensitive than the neurodevelopmental ones.

Question b: The selection of IQ as an endpoint for quantification of neurodevelopmental effects and whether it is an appropriate endpoint for benefits analysis for reduced exposure to MeHg

There is no indication that IQ is a good measure of potential impacts of prenatal MeHg exposure. The Seychelles and New Zealand studies did not find statistically significant associations between MeHg exposures and IQ reductions. Testing in the Faroes did not include measures of I Q. Indeed, there was no consensus among the three tests in the design phase that IQ was an important domain that was likely to be affected by MeHg exposure.

As EPRI's NODA comments explain in greater detail, IQ tests are not a validated measure of brain function. Furthermore, the lack of a global IQ measure can mask subtle changes in a specific domain.

Quite simply, the fact that IQ differences can be monetized in a benefits analysis does not make IQ a good measure of MeHg exposure.

Question c: Whether other neurodevelopmental effects can be quantified and are amenable to economic valuation

At this time, The commenter does not offer a response to this question.

Question d: Whether, and if so how, data from the Faroes Islands, New Zealand, and Seychelles Islands studies can be integrated for purposes of a benefits assessment

EPRI's NODA comments explain in great detail why integrating the Faroes, Seychelles and New Zealand results into a meta analysis is not scientifically sound. The commenter agreed with those comments. Factors that hinder integration include: different study populations that have cultural differences and different possible confounders, different testing ages among the study subjects, different diets (the diets in the Seychelles and New Zealand were based largely fish consumption while the diet in the Faroes relied heavily on consumption of pilot whale), differences in exposure measurements (the Faroes researchers used cord blood while the

Seychelles and New Zealand researchers used hair samples), different outcome tests were used in each study, and differences in the covariates measured and included in multivariate analyses. Furthermore, there is no consistent pattern of significant results across studies. If IQ is used as the endpoint in the meta analysis, then a surrogate needs to be found for the Faroes results. The choice of any surrogate is problematic. For all these reasons, the lack of comparability among the three studies precludes combining their results in a meta analysis that could be used in a benefits analysis.

Question e: The choice of the K=1 model for estimating the relationship between exposure and IQ and practical alternatives to that approach

Assuming a K=1 model is inconsistent with the recommendation of the NAS panel which favored a K 1 model.87 A K=1 assumption is also contrary to the results of two statistical analyses of the Seychelles results that are discussed in EPRI's NODA comments. These analyses indicate non-linear associations between MeHg exposures and test performance. Thus, the choice of K=1 model is not yet warranted.

Question f: The appropriateness and consistency of using a linear dose-response model given the RfD established by EPA in 2001 (reflecting NAS review in 2000), which assumes a threshold dose below which there is not likely to be an appreciable risk of deleterious effects during a lifetime

In many ways, this question answers itself. A linear dose response model, that presumably passes through the zero point, is inconsistent with the RID that EPA has established for MeHg that assumes a threshold effect level. A linear model is also inconsistent with similar values that have been used by the Agency for Toxic Substances and Disease Registry (ATSDR) and the WHO in their development of RID analogues. As the question notes, the NAS panel, whose report EPA relies on to support its RID, also viewed a threshold model as most appropriate for MeHg.

Unfortunately, the NODA offers scant explanation of why EPA now believes that switching to a linear model is appropriate. EPA offers no explanation as to why it may now, interpret the Faroes, Seychelles and New Zealand results as supporting a linear model. The NODA simply recites, without explanation, that a group of Harvard researchers will likely assume a linear dose-response relationship." The only other hint in the NODA as to why EPA may be considering using a linear model is the "practicality" of using a linear model because it "would allow [EPA] to estimate benefits of reductions in exposure due to power plants without a complete assessment of the other sources of exposure." While a linear model may ease the Agency's burden, it is nonsensical to use such a model if it does not comport with actual scientific observation. Indeed, a linear model will vastly overstate the benefits attributed to limiting Hg emissions from coal-fired power plants. EPA should not change from its RID threshold model without a public review and comment process that at least rivals the one it provided when it last revised its MeHg RID. Merely mentioning that the Agency is considering using a model without a detailed explanation why hardly suffices as adequate notice.

Response:

EPA does not have access to the study data for the three key studies. The only data available to EPA are regression coefficients and other statistics that have been published by the study investigators. Therefore, EPA is not able to conduct any modeling that would examine alternative shapes to the dose-response relationship, including non-linear models. EPA's analysis involves a statistical integration of linear dose-response functions that have been reported by the study investigators. We believe that use of a linear function, in conjunction with using a nonthreshold model, in our analysis is well-justified by the following considerations: 1) The National Research Council's 2000 report on methylmercury used linear model results for deriving benchmark doses, and cautioned against use of supralinear models; 2) the Faroe Islands research team reported that K-power models (with the NRC-recommended constraint of K ≥1, i.e., with supralinearity excluded) fit best with the linear specification, i.e., K = 1; 3) linear model results are available for IQ for all three studies, and no non-linear model results are available from the three studies (except for Faroes log model), and raw data are not available to us for conducting analysis of dose-response shape or other issues; and 4) the lowest exposures in the Faroe Islands study overlap with U.S. exposure range, although there is less overlap with the other two studies. Nonetheless, EPA's Reference Dose and the analysis supporting its derivation was reviewed positively by the National Academcy of Sciences and the Agency continues to support its level and the implications. We conclude that any analysis of the IQ benefits needs to deploy several models -- with a threshold and without to capture the full range of uncertainty. EPA acknowledges that there are complexities, including a variety of potential confounders, that must be considered in relation to potential cardiovascular mortality linked to methylmercury exposure. For additional discussion of this endpoint, see Appendix D.

D. Other Comments

Comment:

One commenter (OAR-2002-0056-5476) reports that to date, it has yet to receive any responses to its request to EPA Region 5 to fulfill their Trust responsibilities and intervene on the commenter's behalf in the rule-making process. Therefore, this commenter is calling on EPA Headquarters to act on its behalf and set MACT standards that will reduce Hg emissions from utilities by 90 percent in the next 10 years. This will also fulfill EPA's obligations under the Environmental Justice Doctrine. As outlined in the Forest County Potawatomi's comment letter to EPA (see e-docket OAR-2002-0056-2173: April 27, 2004), EPA has recognized its special obligation to protect the environmental interests of the commenter when carrying out its duties. The Indian Policy, first adopted in 1984, also calls for EPA to work directly with tribes on a government-to-government basis and to encourage tribes to participate in policy-making. It has not been made known to the commenter of any efforts that EPA has made to fulfill any of these obligations. No consultation has taken place with the commenter, and the commenter's requests for Trust responsibility to be carried out have remained unaddressed.

Response:

EPA recognizes that the Federal government stands in a government-to-government relationship with Federally recognized Tribes and has certain trust responsibilities to these Tribes. This relationship and responsibility should guide EPA in the implementation of policies and actions that affect Tribes. Pursuant to the government-to-government relationship, EPA consults with Tribes regarding actions that affect Tribes. In addition, treaties, statutes, and executive orders create Federal obligations regarding Tribal resources. EPA believes that its actions in developing the final rule have been consistent with the government-to-government relationship and that the final rule itself is consistent with the trust responsibility.

EPA does not agree with the commenters who claim that it did not consult with tribes in developing the rule. As explained in the discussion of EPA compliance with EO in the preamble for the final rule, EPA took the following steps to consult with Tribes. EPA gave a presentation to a national meeting of the National Tribal Environmental Council (NTEC) in April 2001, and encouraged Tribal input at an early stage. EPA then worked with NTEC to find a Tribal representative to participate in the workgroup developing the rule, and included a representative from the Navajo Nation as a member the official workgroup, with a representative from the Campo Band later added as an alternate. In March 2004, EPA provided a briefing for Tribal representatives, the newly formed National Tribal Air Association (NTAA), and NTEC. EPA received comments on this rule from a number of Tribes, and has taken those comments and other input from Tribal representatives into consideration in development of this rule.

EPA disagrees that the rule will not adequately protect Tribal fishing rights. EPA agrees that some Tribes have unique legal rights to fish arising from treaties, statutes, executive orders, and agreements. EPA also recognizes that Tribal members may catch and consume more fish than the general public as a result of Tribal fishing rights as well as Tribal culture, traditions, and subsistence lifestyles.

EPA believes that this regulation adequately protects Tribal health and is consistent with the trust responsibility for several reasons. First, the commenters understate the significance of the fact that Hg emissions from Utility Units currently are not subject to performance standards. This regulation will for the first time establish performance standards applicable to Hg emissions, and those standards will require significant reductions in the levels of Hg emissions. Such reductions will provide greater protection to Tribal fish resources than would otherwise be available. Acting to provide such heightened protection is consistent with both the statute and the Federal trust responsibility.

Moreover, the commenters offer no specific evidence that the Hg emissions reductions from this regulation will not adequately protect Tribal health. Their main contention is that the regulatory approach set forth in an earlier EPA proposal would have produced a 90 percent reduction in Hg emissions and that any smaller reduction is, therefore, inadequate. That contention rests on a misconception of an earlier Federal Register Notice, which proposed a finding, but did not contain any specific proposal for Hg emissions regulations, and, therefore, did not provide for any percentage of reduction. EPA has never proposed any such rule. EPA believes that this regulation will adequately protect Tribal health.

The commenters also argue that EPA has not adequately considered the significance of Tribal fish consumption patterns, specifically the fact that Tribal fishers consume more fish than the general population. That comment is misplaced. As described in more detail elsewhere in this document, EPA carefully analyzed available information on fish consumption by Tribal members and other sub-populations, and determined how to use the available data most appropriately. One basis for EPA's analysis was a study of tribal fish consumption in one region to model consumption by other Tribes as well as other subpopulations. EPA's approach was to identify areas where the effects of Hg deposition from utility emissions had the greatest effects. EPA then compared those high-deposition areas with locations with high Tribal populations to assess the areas of greatest potential risk to Tribes. That analysis found that very few areas where Native Americans live corresponds with high residual Hg deposition caused by utilities. It found further, that the standards established in the regulation will significantly reduce risks to tribal members.

Finally, as discussed in the preamble to the regulation, this regulation establishes a cap-and-trade program for Indian country.

As part of its analysis of the this final rule, EPA has estimated the some of the health benefits of reducing Hg from utilities. At this time EPA is only able to provide quantative estimates of the benefits of reducing neurological impacts of exposure to MeHg for a portion of the U.S. population. This population covers people who recreationally catch and consume freshwater fish. The RIA for this rule contains this analysis in Chapter 11. As part of its assessment, EPA provides estimates for the benefits of this rulemaking to subsistence fishers, including case study examples of the benefits to the some members of the Chippewa Tribe, the Hmong, and low income fishers.

Comment:

One commenter (OAR-2002-0056-5476) notes that EPA has a specific obligation to protect tribal way of life and cultural resources, not only rights and resources. Court decisions have held that trust responsibility is not limited to the protection of treaty rights, reservation lands, and other property held in trust for the tribes and that federal agencies may not permit actions which would interfere with treaty rights. Instead, trust responsibility extends to all actions of the federal governments that may affect Indian tribes, including those rights, resources, and interests recognized under treaty, statue, executive order, and common law.

The commenter's rights include rights to the lands, waters, and natural environment of the Reservation. Arizona v. California, 373 U.S. 546 (1963) holds that tribes are entitled to sufficient water and other resources to make the Reservation livable and to maintain their way of life. Tribes also hold rights to hunt, fish and gather on reservation lands and waters.

In addition, Congress has specifically recognized the applicability of the trust responsibility in tribal cultural resources by instating a number of federal laws in this area. Further, the Tribes' right to practice traditional religions under the First Amendment is recognized in the American Indian Religious Freedom Act, 42 U.S.C. Section 1996, 1996a. The

EPA has fallen far short of its obligations in this rulemaking.

Though the Environmental Justice guidelines dictate that EPA must identify and address disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations, unfortunately, it appears as though these guidelines are being largely ignored for the purposes of providing special treatment to utilities. The commenter encourages EPA to assure the Tribes that EPA is actively addressing these Environmental Justice issues per the guidelines EPA has set out for itself.

Response:

EPA recognizes that the Federal government stands in a government-to-government relationship with Federally recognized Tribes and has certain trust responsibilities to these Tribes. This relationship and responsibility should guide EPA in the implementation of policies and actions that affect Tribes. Pursuant to the government-to-government relationship, EPA consults with Tribes regarding actions that affect Tribes. In addition, treaties, statutes, and executive orders create Federal obligations regarding Tribal resources. EPA believes that its actions in developing the final rule have been consistent with the government-to-government relationship and that the final rule itself is consistent with the trust responsibility.

EPA does not agree with the commenters who claim that it did not consult with tribes in developing the rule. As explained in the discussion of EPA compliance with EO in the preamble for the final rule, EPA took the following steps to consult with Tribes. EPA gave a presentation to a national meeting of the National Tribal Environmental Council (NTEC) in April 2001, and encouraged Tribal input at an early stage. EPA then worked with NTEC to find a Tribal representative to participate in the workgroup developing the rule, and included a representative from the Navajo Nation as a member the official workgroup, with a representative from the Campo Band later added as an alternate. In March 2004, EPA provided a briefing for Tribal representatives, the newly formed National Tribal Air Association (NTAA), and NTEC. EPA received comments on this rule from a number of Tribes, and has taken those comments and other input from Tribal representatives into consideration in development of this rule.

EPA disagrees that the rule will not adequately protect Tribal fishing rights. EPA agrees that some Tribes have unique legal rights to fish arising from treaties, statutes, executive orders, and agreements. EPA also recognizes that Tribal members may catch and consume more fish than the general public as a result of Tribal fishing rights as well as Tribal culture, traditions, and subsistence lifestyles.

EPA believes that this regulation adequately protects Tribal health and is consistent with the trust responsibility for several reasons. First, the commenters understate the significance of the fact that Hg emissions from Utility Units currently are not subject to performance standards. This regulation will for the first time establish performance standards applicable to Hg emissions, and those standards will require significant reductions in the levels of Hg emissions. Such reductions will provide greater protection to Tribal fish resources than would otherwise be

available. Acting to provide such heightened protection is consistent with both the statute and the Federal trust responsibility.

Moreover, the commenters offer no specific evidence that the Hg emissions reductions from this regulation will not adequately protect Tribal health. Their main contention is that the regulatory approach set forth in an earlier EPA proposal would have produced a 90 percent reduction in Hg emissions and that any smaller reduction is, therefore, inadequate. That contention rests on a misconception of an earlier Federal Register Notice, which proposed a finding, but did not contain any specific proposal for Hg emissions regulations, and, therefore, did not provide for any percentage of reduction. EPA has never proposed any such rule. EPA believes that this regulation will adequately protect Tribal health.

The commenters also argue that EPA has not adequately considered the significance of Tribal fish consumption patterns, specifically the fact that Tribal fishers consume more fish than the general population. That comment is misplaced. As described in more detail elsewhere in this document, EPA carefully analyzed available information on fish consumption by Tribal members and other sub-populations, and determined how to use the available data most appropriately. One basis for EPA's analysis was a study of tribal fish consumption in one region to model consumption by other Tribes as well as other subpopulations. EPA's approach was to identify areas where the effects of Hg deposition from utility emissions had the greatest effects. EPA then compared those high-deposition areas with locations with high Tribal populations to assess the areas of greatest potential risk to Tribes. That analysis found that very few areas where Native Americans live corresponds with high residual Hg deposition caused by utilities. It found further, that the standards established in the regulation will significantly reduce risks to tribal members.

Finally, as discussed in the preamble to the regulation, this regulation establishes a cap-and-trade program for Indian country.

As part of its analysis of the this final rule, EPA has estimated the some of the health benefits of reducing Hg from utilities. At this time EPA is only able to provide quantative estimates of the benefits of reducing neurological impacts of exposure to MeHg for a portion of the U.S. population. This population covers people who recreationally catch and consume freshwater fish. The RIA for this rule contains this analysis in Chapter 11. As part of its assessment, EPA provides estimates for the benefits of this rulemaking to subsistence fishers, including case study examples of the benefits to the some members of the Chippewa Tribe, the Hmong, and low income fishers.

Comment

One commenter (OAR-2002-0056-5492) made the following recommendations to the EPA regarding development of a final proposal for Hg control:

- Carbon Injection (ACI) is maturing quickly. Using a methodology that says subbituminous coal needs a credit multiplier or higher emissions, results in fuel bias

against bituminous coal and the states that produce bituminous coal.

- The commenter believes that wet ESPs and SCRs remove more oxidized Hg than EPA results show.

- The western coal state congressional delegations, who are saying that technology will not be available to remove Hg from their sub-bituminous coal, are ignoring the benefits America has already received from investments in developing clean coal technology for Hg removal and punishing bituminous coal users.

- A MACT standard should be fuel neutral, i.e., no separate standards for different coal ranks.

- A fuel-neutral MACT of 3.0 lbs Hg/TBtu or less for existing EGUs will reduce Hg emissions to less than 34 tons/year.

- A MACT standard should incorporate an alternative method to calculate plant Hg emissions limits based on a percent reduction from the raw coal as mined. Such an alternative would provide some amount of relief for those coals with unusually high Hg content while still achieving meaningful reductions.

- Under the alternative cap and trade proposals, implementation dates should be adjusted to coincide with other regulatory actions, including the Clean Air Interstate Rule and multi-pollutant strategies such as Clear Skies.

- A cap and trade rule should not include Fuel Adjustment Factors.

- A cap and trade rule should address so-called “hot spots” that could result from allowance trading.

The commenter appreciated the opportunity to provide comments to the U.S. EPA regarding the proposed Hg regulations. The commenter would be pleased to provide additional information and are willing to meet with the U.S. EPA regarding our statement.

Response:

EPA has examined the commenter's concerns in context of the final rulemaking. EPA is finalizing a cap-and-trade approach under section 111. Please see the Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units and the Removal of Coal- and Oil-fired Electric Utility Steam Generating Units from the Section 112(c) List for a discussion of the Agency’s rationale for not proceeding under Section 112.

EPA appreciates the commenter's input to the record on the status of control

technologies. The Agency's position on the state of Hg technology is contained in the EPA 's Office of Research and Development white paper (see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005).

Comment:

One commenter (OAR-2002-0056-5571) reports key public power concerns in response to the EPA NODA. This commenter prefers a cap and trade approach to controlling Hg without disadvantaging smaller utilities with only one generating unit or few fuel options. The commenter endorses comments from UARG and PERI.

The commenter continues to support an exemption for small units and requests that EPA streamline the monitoring requirements for small and/or exempt units regardless of decision to use cap and trade approach (Sec. 111 or 112 (n) (1) (A) or MACT Approach:

The commenter believes that EPA should provide for alternative treatment for small utilities ~50 MW. (Questions 5 & 6)

With regard to de minimis threshold, this commenter continues to support EPA's suggested exemption for units that emit less than 25 pounds of Hg annually, and encourages EPA to extend the exemption to units that emit up to 50 pounds a year. EPA's re-examination of the benefits associated with the Utility MACT in the NODA lends further support to an exemption. As EPA notes in the NODA, there are open issues regarding the benefits of the total Hg reductions being proposed in the Utility MACT for all electric utility steam generating units in the U.S. This issue is even more relevant to the minimal emissions from small units, where the costs of monitoring and compliance are clearly significant, but the benefits are small and uncertain. For this reason, and the others set out in the commenter's previous comments in this rulemaking, including the likelihood that many of the commenter's smaller units will be forced to close under the pressure of the Utility MACT rule and the Clean Air Interstate Rule (CAIR rule), and the impacts of that on the national transmission grid), the commenter requests that EPA exempt these small units from the Utility MACT.

Response:

As discussed above and in the final rule preamble (section IV.D.3.iv), EPA is not finalizing a low-emitter exclusion and EPA recommends States address small business entities through the allocation process.

Comment:

With regard to monitoring for smaller utilities, one commenter (OAR-2002-0056-5571) requests that EPA also simplify monitoring for smaller and/ or exempt units. Monitoring costs present a significant compliance cost, particularly for small units, and one that is unwarranted in light of the minimal risk that these units pose. For an exempt unit, the monitoring costs to prove

that a unit is exempt could prove to be as significant as the costs of compliance with the rule, thereby defeating the purpose of the exemption. EPA estimates the capital cost of Hg CEMS range from $95,000 to $135,000. Annual operating and maintenance costs are estimated to range between $45,000 to $65,000. Under the upper end of the range, the first year's monitoring cost, equal to $200,000 per year, would be in the same range as controlling for Hg through allowance purchases ($20,000) for a unit that emitted, as many of the commenter's members do, about 10 pounds per year.

The commenter notes that not only are the monitoring costs for these small units enormous, but they are particularly inappropriate in light of the minimal risks presented by small units. Units subject to a 50 pound exemption account for a small fraction of the Hg emitted in the U.S. The total Hg emissions from these units are just over 6 tons per year, or less than 15 percent of the Hg emitted from all coal-fired power plants. The emissions for all units less than 25 pounds are less than 2 tons per year, or less than 5 percent of total Hg emissions. Further, as EPA notes in the NODA, there are open issues regarding the benefits of the total Hg reductions from all utilities in the U.S. discussed in the Utility MACT. This raises serious questions about the even smaller and less certain benefits of regulating small emitters, particularly when monitoring and compliance costs for the small emitters are substantial.

The commenter recommends that for these small and/or exempt units, EPA adopt the Hg monitoring requirements that have already been developed for small units in the context of another MACT rulemaking. The MACT for Industrial, Commercial and Institutional Boilers and Process Heaters applies to utility boilers that generate equal to or less than 25 MW (as well as industrial units that generate less than 25 MW) and includes requirements for Hg testing. See National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 69 Fed. Reg. 55,218 (September 13, 2004). These testing requirements are particularly appropriate for the smaller units in the Utility MACT, which have significant similarities to the units in the Boiler MACT, including small size and limited emissions.

The monitoring requirements for the Boiler MACT include initial and annual stack tests (using EPA method 29, Part 60, Appendix A or ASTM D6784-02), or, in the alternative, fuel testing (using ASTM D3684-01, see Table 6 attached). The general monitoring requirements from the Industrial Boiler MACT are attached in Appendix II to these comments. These monitoring requirements, including the continuous compliance requirements, are more appropriate to small and/or exempt units in the Utility MACT rule than the significant costs associated with CEMS, while ensuring that these units continue to qualify as small and/or exempt.

If EPA determines that Boiler MACT monitoring requirements cannot be used of Utility MACT, the commenter also encourages the EPA to adopt phased-in monitoring requirements for small and/or exempt units. There are still significant uncertainties associated with the current monitoring technology. These technology issues will present a particular hardship on municipally owned utilities. Smaller municipal utilities face substantial challenges because they

lack the resources to address these monitoring issues and are unable to get priority in hiring consultants. EPA should delay the Hg monitoring requirements for exempt and/or small sources until at least 2010 when Hg monitoring technology may be more fully developed, demonstrated, and less expensive.

Response:

As discussed above and in the final rule preamble (section IV.D.3.iv), EPA is not finalizing a low-emitter exclusion and EPA recommends States address small business entities through the allocation process.

Comment:

One commenter (OAR-2002-0056-5571) believed that should a cap-and-trade program be implemented, EPA has proposed an exemption for small emitters. It suggests an exemption for units that emit 25 pounds or less. According to EPA's data, this would apply to 3.9 percent of emissions nationwide. The commenter believed that EPA should restyle the small emitter exemption so that it applies to existing units at small plants emitting, with a minimum of 25 pounds on a per unit basis.

Response:

As discussed above and in the final rule preamble (section IV.D.3.iv), EPA is not finalizing a low-emitter exclusion and EPA recommends States address small business entities through the allocation process.

Comment:

One commenter (OAR-2002-0056-5571) urges the EPA to also consider other de minimis options offered by public power communities (including the >95 pound plant wide suggestion for community utilities that meet the SBREFA definition). Earlier the commenter provided references to the UMRA, Regulatory Flexibility Act, SBREFA Act of 1996 and Executive Order 12866 that would justify making some practical decisions about a de minimis exemption. Whatever de minimis level the EPA ultimately sets in the final rule. The commenter does not believe that this de minimis should not subject the larger units/plants to more stringent cap levels.

Response:

As discussed above and in the final rule preamble (section IV.D.3.iv), EPA is not finalizing a low-emitter exclusion and EPA recommends States address small business entities through the allocation process.

Comment:

One commenter (OAR-2002-0056-5571) believes that the EPA's final rule should emphatically state that the smaller utility systems (particularly those that meet the SBREFA definition) should be able to work with their state agencies and permit writers to determine the most practical and reliable method to perform monitoring functions at lowest cost (considering capital expense, operating and maintenance, and on-going staff training expenses). Many public power utilities simply don't have the personnel skills to perform these highly sophisticated monitoring runs. Also many public power communities are two hours away from major metropolitan areas or airport hubs so that frequent visits by CEM manufacturers, vendors, contractors, or service personnel would be prohibitively expensive.

Response:

As discussed above and in the final rule preamble (section IV.D.3.iv), EPA is not finalizing a low-emitter exclusion and EPA recommends States address small business entities through the allocation process.

Comment:

One commenter (OAR-2002-0056-5571) strongly urges the U.S. EPA to encourage states to work with the smaller Hg emitters to allow creative Hg reduction/mitigation/removal or prevention projects. Holland Board of Public Works is a municipal utility with approximately 30,000 households in Michigan. Earlier in 2004 the municipal utility initiated a community program to encourage the voluntary return of Hg thermometers to reduce Hg from household environments, landfills and the wastewater system. The utility provided digital thermometers to those who returned a glass thermometer containing Hg or other Hg-containing items. In the span of a few months the Holland Board of Public Works collected 28 pounds of Hg through this program in addition to working with commercial industrial customers. Comparatively, the Holland Board of Public Works emits approximately 8 pounds of total Hg annually through combined oil, coal and gas generation. The commenter believes that the EPA and states should encourage alternative methods like this innovative method to reduce Hg that are cost effective in the final rule. The Clean Air Act authorized the EPA to consider work practices and other alternatives when they are demonstrated to be effective and can be proven. The commenter strongly urges the EPA to allow state agencies to work with smaller emitters on this type of alternative to MACT if the EPA promulgates a MACT standard or if it authorizes a cap and trade program that a state declines to opt into.

Response:

As discussed above and in the final rule preamble (section IV.D.3.iv), EPA is not finalizing a low-emitter exclusion and EPA recommends States address small business entities through the allocation process.

Comment:

The commenter (OAR-2002-0056-5455) also took issue with the modeling performed in the analysis. The commenter does not believe the science of modeling has reached a point where it can accurately be used for Hg transport and deposition due to the lack of understanding about dry deposition. Few deposition monitors exist in Indian Country so it's very hard to say how much wet or dry deposition is occurring in these areas 15. Based on this concern, the commenter believed it is reckless to propose a cap and trade program relying on the results of EPA's models. It is better to err on the side of caution than to be wrong in such an important matter. To account for the lack of confidence in the models, EPA should abandon its idea of cap and trade and stick to a MACT standard.

The commenter believed that the air emission inventories used in EPA's analysis probably underestimated the amount of Hg emitted from some sources, such as miscellaneous product disposal. EPA has used the best information it has available, but it should leave a margin of safety to account for inaccuracies.

Response:

EPA is finalizing a cap-and-trade approach under section 111. Please see the Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units and the Removal of Coal- and Oil-fired Electric Utility Steam Generating Units from the Section 112(c) List for a discussion of the Agency's rationale for not proceeding under Section 112.

Comment:

The commenter (OAR-2002-0056-5551) stated that firstly, standards for controlling HAPs from coal fired power plants must follow the requirements of Section 112 of the Clean Air Act. The commenter noted that for existing power plants, each MACT limit must be at least as stringent as the limit which is achievable by the average of the best controlled 12 percent of similar units for which there is data. The commenter noted that this is commonly referred to as the MACT floor. The commenter stated that the standards should be more stringent if justified by cost, benefit and feasibility. According to the commenter, hence, the NODA information on costs and benefits is primarily relevant for setting more stringent standards than the MACT floor. The commenter believed that the NODA is useful for setting MACT standards better than the MACT floor for subbituminous and lignite coal combustion, if a coal neutral standard is not set. The commenter stated that, however, information on costs and benefits are irrelevant to the setting of the MACT floor.

While the commenter believed that the choice of 3 mg per MWh or 90 percent control, annual averages, is an appropriate MACT standard for all coals, the commenter noted that EPA may choose to set MACT limits by principle coal type, i.e., bituminous, subbituminous, and lignite. In such an event, the commenter recommended that EPA set better than the MACT floor limits for subbituminous and lignite coals in view of the generally limited control systems currently in place for these coals and the recent success in controlling Hg from these coals using

halogenated activated carbon injection. The commenter stated that the rate component of the standard should remain the same as bituminous coal to facilitate compliance determination for blended coals. The commenter added that, alternatively, blended coals should be subject to the most stringent rate for the coals being blended. The commenter stated that the control efficiency component of a MACT limit for subbituminous and lignite coals could be somewhat less stringent than for bituminous coals, in view of the somewhat lower Hg content of these coals and the lesser amount of data for control of Hg from these coals. According to the commenter, 3 mg per MWhr or 80 percent control would be a reasonable MACT standard for these coals at this time.

Response:

EPA is finalizing a cap-and-trade approach under section 111. Please see the Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units and the Removal of Coal- and Oil-fired Electric Utility Steam Generating Units from the Section 112(c) List for a discussion of the Agency's rationale for not proceeding under Section 112.

RESPONSE TO SIGNIFICANT PUBLIC COMMENTS ON THE PROPOSED CLEAN AIR MERCURY RULE

Received in response to:

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 4652; January 30, 2004)

Supplemental Notice for the Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 12398; March 16, 2004)

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources, Electric Utility Steam Generating Units: Notice of Data Availability
(69 FR 69864; December 1, 2004)

Docket Number OAR-2002-0056

10.0 OTHER

US Environmental Protection Agency
Emissions Standards Division
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

15 March 2005

General Outline

10.0 OTHER

10.1 OTHER MERCURY SOURCES

Comment:

One commenter (OAR-2002-0056-2695) requested that the final rule address Hg emissions from international sources. A second commenter (OAR-2002-0056-3552) noted that a global approach will be needed to address emissions from international sources because areas west of the Mississippi River receive less total Hg deposition, but a higher total Hg deposition from sources outside the U.S.

Response:

Anthropogenic Hg emissions from the U.S. are estimated to account for roughly three percent of total global emissions, and emissions from the U.S. power sector are estimated to account for about one percent of global emissions. (United Nations Environment Programme. Chemicals, Global Mercury Assessment, Geneva, 2002.). Although the U.S. has no legal authority to regulate Hg emission sources outside its boundaries, the U.S. is a leader in promoting and facilitating global reductions in Hg use and releases.

The U.S. engages international partners, multilaterally and bilaterally, to address key Hg issues including data collection and inventory development, source characterization, and best practices for emissions and use reduction. Most recently, the U.S. has provided leadership in the United Nations Environment Program (UNEP) Governing Council (GC). In 2003, the UNEP GC adopted a U.S. proposal establishing the UNEP Mercury Program to facilitate and conduct technical assistance and capacity building to support efforts of developing countries and countries with economies in transition to take action regarding Hg pollution. In February 2005, the UNEP GC adopted a U.S. proposal that accelerates the work of the UNEP Mercury program by engaging countries in partnerships and collaborative activities to produce tangible results in the near term by facilitating global reductions in Hg exposure, use, and release. This agreement will advance specific projects in key source countries and priority sectors by engaging a diverse array of stakeholders, including governments, the private sector, international organizations, and nongovernmental organizations, to leverage resources, technical capacity and expertise.

Other examples of U.S. international efforts in this area include our work with the Arctic Council Action Plan (ACAP) and the Arctic Monitoring and Assessment Program (AMAP) to strengthen capacity building and technical cooperation program; and our support for the development of Russia's Hg action plan and inventory, as well as support for a regional Arctic inventory and emissions reductions projects. The U.S. has also developed bilateral Hg cooperation programs to foster assessment and sector specific improvements in China and India.

The U.S. has been a global leader in taking actions to address our domestic Hg emissions. Now, the U.S. is the first country in the world with plans to regulate Hg emissions

from power plants. We believe that this section 111 regulation will further the leadership of the U.S. in this area as well as encourage development of Hg control technologies that may be utilized worldwide.

Comment:

Eight commenters (OAR-2002-0056-1327, -1471, -1611, -1664, -2110, -2219, -2878, -3457) stated that it is unclear how the U.S. will meet its obligations under the Great Lakes Water Quality Agreement, Great Lakes Binational Toxics Strategy, New England Governors and Eastern Canadian Premiers Mercury Action Plan, and the 1998 Protocol to the Convention on Long-Range Transboundary Air Pollution signed by the U.S., Canada and Europe, and other international agreements because the proposal would allow such high emissions of Hg.

Response:

EPA believes that the final rule will significantly reduce Hg emissions, as is explained more fully in the preamble and elsewhere in this response to comments document and the rulemaking record. Thus the rule will advance the objectives of the international instruments cited by the commenters.

Comment:

One commenter (OAR-2002-0056-1436) stated that EPA should be more concerned about Hg as a preservative in vaccinations.

Response:

Approving the use of Hg as a preservative in vaccines is not within EPA's authority. Such authority rests with the U.S. Food and Drug Administration (FDA). Information on Hg in vaccines (thimerosol) may be found at http://www.fda.gov/cber/vaccine/thimerosal.htm and at http://www.cdc.gov/nip/vacsafe/concerns/thimerosal/default.htm.

Comment:

Numerous commenters (OAR-2002-0056-2695, -3552, and others listed in this paragraph) pointed out the need to address other sources of Hg emissions. Several commenters (OAR-2002-0056-1104, -1251, -1293, -1308, -1530, -1611, -2729, -2750, -2765, -2981, -3243, -3122, -3657, -4050, -4410, -4417, -4620, -4718, -5007) stated that Hg should be banned from all products (e.g., dental amalgam, vaccinations, additives in paints and pesticides, electronic equipment), and that emissions from all other industrial sources (industrial boilers, hazardous waste incinerators, Cl production) need to be controlled. Several of these commenters described severe health effects from dental amalgam. One commenter (OAR-2002-0056-3199) supported control of Hg emissions from coal-fired power plants, but noted that power plants were not the only sources of Hg and stated that a better inventory of all sources (e.g., chlor-alkali plants, automobile/white goods scrap yards, and shredders [including furnaces using products from

shredders], etc.) was needed. The commenter stated that these emissions were also significant and merited further study.

Response:

A number of the sources of Hg exposure noted by the commenters (e.g., dental amalgam, vaccinations) are not within the statutory authority of the EPA. As noted earlier, approving Hg use in vaccinations is under the authority of the FDA. Similarly, dental amalgams fall under the purview of the FDA; information on the research being conducted on the use of mercury in dental amalgams may be found at http://www.fda.gov/OHRMS/DOCKETS/98fr/03-11648.html and consumer information on the use of Hg in dental amalgams may be found at http://www.fda.gov/cdrh/consumer/amalgams.html. Information about activities on many of the other sources noted by the commenters may be found through www.epa.gov/mercury. EPA agrees that coal-fired utility units are not the only source of Hg in the U.S.; the industrial sources of Hg noted by the commenters are the subject of other regulatory efforts by EPA under the CAA. In 1990, more than two-thirds of U.S. anthropogenic Hg emissions came from just three industrial source categories: coal fired power plants, municipal waste combustion, and medical waste incineration. In 1990, EPA issued final regulations for large municipal waste combustors (MWC), a sector which emitted approximately 57 tons of Hg emissions. Implementation of large MWC regulations has reduced Hg emissions by 88 percent from 1990 emission levels. In 2005, these regulations are projected to reduce MWC emissions by 91 percent from 1990 emission levels. Medical waste incerators are also subject to stringent emissions standards, and have reduced Hg emissions by 97 percent from 1990 emissions.

Regulations to limit Hg emissions from chlorine production facilities that use Hg cells and regulation of industrial boilers, will further reduce emissions of Hg when they become effective in the next few years. EPA issued final standards for Hg from chlor-alkali production on December 19, 2003. EPA expects that these standards, when fully implemented by the end of 2006, will cut Hg emissions from point sources at these facilities by 74 percent and will cut total Hg reductions from these facilities by about 11 percent from 1999 emission levels. EPA has also issued regulations to reduce Hg emissions from industrial boilers. EPA estimates that this regulation, when fully implemented in 2007, will reduce emissions by 17 percent from 12 tons to 10 tons per year.

In addition, actions to limit the use of Hg, most notably Congressional action to limit the use of Hg in batteries and EPA regulatory limits on the use of Hg in paint, reduced the Hg content of waste contributed to the reduction of Hg emissions from waste combustion during the 1990s.

Comment:

One commenter (OAR-2002-0056-3426) stated that policymakers should implement regulations to obtain maximum control of Hg from all sources with uniform limits, develop scientifically-based fish consumption guidelines that ensure that 98 percent of the population is within EPA's safe level of MeHg exposure, and cooperate internationally to reduce the global problem.

Response:

EPA is working along the lines that the commenter suggests. As discussed in responses to comments presented elsewhere in this document above, regulations are being established for the significant Hg-emitting sources based on the requirements of the CAA. In addition, as discussed above, EPA is working with the international community to address emissions of Hg. EPA believes that the final utility rule will serve to reduce deposition of Hg and, thus, lead to improvements in fish tissue Hg concentrations.

Comment:

One commenter (OAR-2002-0056-3543) recommended that the final rule address the disposal of Hg removed from the air emissions. The commenter felt that, from the perspective of watershed and fish contamination, no progress would be made if only the route of contamination (but not the extent) were changed.

Response:

This is an area of research that EPA continues to pursue through its Offices of Research and Development and Solid Waste, in coordination with other Federal agencies and industry groups. The findings to-date indicate that, for most management practices, leaching of Hg does not appear to be of concern for land disposal of coal combustion residues (CCR), including from those sources where carbon sorbents have been tested for Hg control. ("Potential for Cross-Media Transfers from Management of Mercury-Enriched Coal Combustion Residues," OAR-2002-0056-6139) Further evaluation is warranted to understand whether the extent of this leaching would pose a potential concern.

10.2 STAKEHOLDER INFLUENCE

Comment:

Many commenters specifically criticized industry influence on EPA's rulemaking. Many commenters stated that the proposals favor the industry over public health. Many pointed to the use of Latham and Watkins language in the preamble. One commenter (OAR-2002-0056-2160) specifically stated that whole sections were lifted from the report of a firm representing interests of western coal producers. The science used by EPA in establishing the limits for bituminous and subbituminous coal was questioned because of the undue influence of certain constituent groups. Two Congressmen requested detailed information on this rulemaking process.

Response:

EPA is aware of the concern expressed by the commenters and has responded to the Congressional inquiries. The material in question was provided to the EPA through the Clean Air Act Advisory Committee working group process established under the Federal Advisory Committee Act (FACA) and, thus, we do not feel that its use was inappropriate.

Comment:

One commenter (OAR-2002-0056-3517) urged EPA to balance comments received from the various stakeholders to make sure that the Hg rules do not become a driver for the coal market.

Response:

EPA has considered all comments received on or before January 3, 2005, in developing the final rule.

Comment:

One commenter (OAR-2002-0056-2248) stated that the involvement of a senior EPA official in both the Hg lawsuit against the Agency and in EPA's settlement of the matter presented the appearance of a conflict of interest that must be investigated to preserve the right to constitutional due process. The commenter felt that a potentially serious conflict of interest overshadowed the current rulemaking, and that the presence of David Doniger as a senior member of EPA's air office during this rulemaking, as well as his participation in the matter at EPA, raised serious questions about the rulemaking's transparency and validity. The commenter asserted that this official's participation in the rulemaking violated the fundamental constitutional right of due process and necessitated postponement of further action on the rule until this apparent conflict has been fully investigated.

Response:

The issue noted by the commenter is the subject of a Freedom of Information Act (FOIA) by the commenter and, thus, EPA can not respond at this time to the comment.

10.3 LEGAL ISSUES

10.3.1 Broad Authority Under CAA Section 111(d)

Comment:

Four commenters (OAR-2002-0056-2224, -2835, -2867, -2922) filed comments to supplement EPA's discussion of its statutory authority to regulate under CAA section 111 and to establish a cap-and-trade program. They stated that CAA section 111 confers broad legal authority for the regulation of existing sources under a Federal-State partnership. The legislative history and the relationship between the plans developed for the State-Federal partnerships under CAA section 110 and section 111 further supports EPA's determination that a flexible emissions trading program can be implemented under section 111(d).

The commenters noted that this partnership contemplates EPA establishing "standards of performance" at the national level and each state developing a regulatory program for

implementing and enforcing those standards at the state level. The commenters pointed out that the statute explicitly notes that the Federal-State partnership under CAA section 111(d) is to be modeled after the regulatory process used under CAA section 110. In that regulatory context, CAA section 110 provides States with wide latitude in developing emissions control strategies for achieving Federal air quality goals — National Ambient Air Quality Standards (NAAQS) established by EPA at the national level.

Both the statute and legislative history confirm that Congress delegated broad legal authority to adopt flexible regulatory mechanisms for controlling existing sources under section 111(d)(1). This broad delegation of authority provides sufficient authority for EPA to establish flexible "standards of performance" that need not prescribe when, how, and the degree to which each affected unit must achieve that emissions limitation — either on a unit-by-unit basis or facility-by-facility basis. In addition, the CAA authorizes States to implement and enforce those standards of performance through cap-and-trade program or other such flexible, market-based mechanism that implements the reduction requirement imposed under the standard of performance, while taking into consideration "the remaining useful life" of the source as well as "other factors." EPA's proposed trading scheme is one effective mechanism for States to address concerns regarding existing units whose remaining useful life is limited such that the purchase of allowances may be appropriate in lieu of making additional major pollution control investments at those units. Commenter OAR-2002-0056-2835 described in detail how this interpretation is confirmed in the legislative history to CAA section 111(d).

Another indication of the broad discretion accorded to EPA and States in implementing and enforcing standards of performance under section 111 (d)(1) is the relationship that this section has with section 110. Section 111 (d)(1) requires EPA to promulgate regulations that establish SIP-like procedures similar to those in section 110 to be used by States in submitting their plans. The CAA section 111(d) plans and SIP programs are complementary to one another – in particular, a State's plan under section 110 (or section 172, for non-attainment areas) can be used to meet the standards under section 111(d). States can thus use the SIP regulatory tools in CAA sections 110(a)(2)(A) and 172(c)(6) to establish "enforceable emissions limitations and other control measures" to achieve this end. One such regulatory tool available to States explicitly referenced under these sections is the adoption of "economic incentives such as fees, marketable permits, and auctions of emissions rights," when developing a plan to comply with the standards under section 111(d)(1).

This complementary relationship was confirmed in EPA's guidance for implementing the Emission Guidelines for Municipal Waste Combustors established under CAA sections 111(d) and 129. EPA's guidance explained that where the SIP requirements are adequate to meet the section 111(d)/129 standard - which are required to be more rigorous than emission guidelines under only section 111(d) - the State has the authority to submit a section 111(d)/129 plan that relies on the requirements of the SIP to meet the section 111 (d)/129 standard. The commenter adds that the section 111(d)/129 rule for Municipal Waste Combustors also clearly contemplated that States would use trading when implementing and enforcing the standards-the rule explicitly provided that a state plan could "establish a program to allow owners or operators of municipal waste combustor plants to engage in trading of nitrogen oxides emission credits."

Commenter OAR-2002-0056-2867 stated that EPA has correctly harmonized these conflicting statutory provisions, and interpreted them in a way that effectuates the purposes of the statute as whole. The commenter agreed that the key provision in the definition of a "standard of performance" under CAA section 111 is the phrase "the best system of emissions reduction." Since this phrase is not defined by statute, EPA has broad discretion in determining what is the "best system of emissions reduction," so long as the system ultimately selected "has been adequately demonstrated." The commenter pointed out the definition places no other explicit statutory constraints on EPA in making this determination, except that it must consider the following factors: the cost of achieving the Hg reductions, non-air quality health and environmental impacts, and energy requirements. The commenter concluded that the statute requires the standards of performance be based on "the degree of emission limitation achievable" by the best system of emissions reduction system selected by EPA. As evidenced by the success of other cap-and-trade programs for the power sector, i.e., the NO_x SIP Call and the Title IV Acid Rain Program, the trading program approach satisfies the statutory requirement for setting the standard of performance based on the best system of emission reduction for the electric utility source category.

The commenter felt it is important to note that the statutory definition does not require specific units or facilities to install emissions control technology. In addition, the definition is silent on whether or not the standard of performance prescribing specific emissions limits should directly apply on a unit-by-unit or facility-by-facility basis. The commenter also noted that the definition is silent on whether each unit or facility must achieve specific reduction levels continuously or averaged over a specific period of time. (Regarding this issue, the commenter pointed out that CAA section 302(1) also contains a definition of the term "standard of performance," which defines the term to mean "a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous emissions reduction." It appears to the commenter that this definition would not be controlling for purposes of setting standards of performance under section 111, given that Congress chose to adopt another specific definition of standard of performance in CAA section 111.

Three commenters (OAR-2002-0056-2224, -2835, -2867) emphasized that CAA section 111(d)(1) itself does not independently mandate that standards of performance for existing sources impose a source-specific requirement for continuous emission reduction. Thus, a State plan incorporating a standard of performance that employs a cap-and-trade mechanism would not conflict with the statutory requirements of section 111(d)(1). However, a strong case can be made for the proposition that the emissions cap and allowance-holding requirement in EPA's proposed section 111(d) trading program impose a "continuous emissions reduction" requirement on affected electric utility units. The proposed cap-and-trade program establishes a permanent cap on Hg emissions and requires affected sources to hold allowances that correspond to the level of Hg emissions from those sources at all times. By its very elements, the proposed cap-and-trade program is a continuous method of emission reduction given that there is no point in time when an affected source can emit Hg without holding allowances that correspond to those emissions. EPA's proposal also requires continuous emissions monitoring to assure that a source complies with the requirements of the cap-and-trade program at all times. Thus, if a court

were ever to construe section 111(d)(1) to require a "continuous emission reduction," the features of EPA's proposed trading program should meet that requirement.

The legislative history of the term "standard of performance," does not specifically reference an allowance trading system as a regulatory mechanism for controlling emissions under CAA section111(d), but generally reflects Congress' intent that existing sources be accorded considerable flexibility in meeting the section 111(d) standards. Such legislative intent for compliance flexibility provides general support for EPA's interpretation that the term "standard of performance" may include an allowance trading program, as proposed in the Hg rule, because such a trading program accords flexibility to sources.

According to the commenter, the Senate debate on the 1990 amendments reinforces this statutory interpretation, in light of Congress' express action removing any specific percent reduction requirement from the concept of "standards of performance." As an example, the commenter states that Senator Baucus explains that Congress adopted a percentage reduction requirement in the 1977 CAA Amendments to ensure that coal-fired electric generating units did not rely on low-sulfur "compliance" coal alone to meet NSPS for SO_2. According to Senator Baucus, a percentage reduction requirement across the board was supposed to require SO_2 scrubbers regardless of the rank of coal combusted; however, this approach accentuated the regional split over coal use that existed prior to 1977. With the adoption of the SO_2 emissions cap under the Title IV acid rain program, the percentage reduction requirement was no longer necessary and could in fact be a barrier to flexible compliance under the acid rain trading program. The commenter continues that accordingly, Congress elected to repeal the percent reduction requirement during the 1990 CAA Amendments.

The commenter also referenced remarks in debate by Senator Bond during the 1990 CAA Amendments that also pertain to the removal of the percentage reduction requirement and, indirectly, the continuous emission reduction requirement. Specifically, Senator Bond explained that both the House and the Senate rejected the concept of the percentage reduction and "directed EPA to come up with an alternative standard that would allow utilities to meet it in the most flexible manner possible." Senator Bond further noted that the new standards could be met by fuel switching, the use of technology and fuel switching, by technology alone, and by intermittent controls or intermittent operation. Senator Bond continued by stating that "[t]he way the language is constructed, intermittent controls can be allowed to comply with this section of the act. So for the first time in 13 years we will have EPA setting. . . emission levels for SO_2 that will not require the use of the scrubbers for compliance."

The commenter stated that this flexibility was not intended to be limited to utility standards, or the operation of the Acid Rain Program, but was to be afforded to all sources subject to "standards of performance" under section 111. The commenter felt it would be ironic if EPA failed to take advantage of the flexibility specifically intended by Congress to benefit the utility industry in the context of developing requirements for Hg control, since EPA itself has not identified any particular control technology as the basis for its standards.

Response:

EPA concurs with the comments.

10.3.2 EPA Must Regulate Under Section 112

Comment:

Several commenters (OAR-2002-0056-2108, -2173, -2330, -2332, -2359, -2575, -2823, -2836, -2871, -2878, -2880, -2889, -2920, -2924, -3393, -3394,-3459, -4139) argued that EPA lacks authority to regulate HAP under section 111.

Response:

Those comments are summarized and responded to in the Response to Comments ("Response to Significant Public Comments Concerning the Proposed Revision of the December 2000 Appropriate and Necessary Finding and the Removal of Utility Units from the Section 112(c) List"). We incorporate those comments and responses herein by reference. EPA also believes it has addressed these concerns in the revision of EPA's CAA section 112(n) determination.

10.3.4 Clean Water Act

Comment:

Many public interest groups (more than 73) contended that EPA completely ignored its statutory obligations to control non-point sources of pollution under Clean Water Act (CWA) section 303(d)(4)(B). Although the CWA does not give EPA direct authority to impose controls on individual non-point sources, EPA is responsible for ensuring that non-point source pollution does not undermine state water quality goals. Atmospheric deposition of Hg from power plants is an acknowledged and significant source of non-point source pollution. The relaxed controls under the proposed rule will lead to decreasing waster quality and violations of state water quality standards. EPA must implement Hg non-point source controls that meet best management practices of the CWA's antidegradation provisions. Commenter OAR-2002-0056-2575 stated that EPA utterly failed to consider the CWA compliance implications of the proposal or of their own collaborative effort to reduce deposition of toxics to all waterbodies through their Air-Water Interface Work Plan general strategy.

Response:

Commenters cite to section 303(d)(4)((B) of the Clean Water Act (CWA) and assert that EPA has ignored its statutory obligations under the CWA to control nonpoint sources of pollution. Commenters are mistaken regarding EPA's obligations or authorities under the CWA to control nonpoint sources of pollution. Section 303(d)(4)(B) is a provision that addresses when a permitting authority may include less stringent effluent limitations in a point source NPDES permit. The section does not address nonpoint sources of pollution. There is a reference in CWA section 303(d)(4)(B) to EPA's antidegradation policy. EPA's antidegradation

policy, however, does not authorize EPA to regulate, or compel States to regulate, nonpoint sources of pollution. See American Wildlands, et al. v. Browner et al., 260 F.3d 1192, 1198 (10th Cir. 2001)) Commenters appear to admit as much when they say that "the CWA does not give EPA direct authority to impose controls on individual nonpoint sources . . ." To the extent that commenters believe that the CWA or EPA's antidegradation policy obligates, or gives authority to, EPA to regulate or compel States to regulate nonpoint sources of pollution, commenters are wrong and their position is unsupported by relevant case law. As the U.S. Court of Appeals for the Fourth Circuit has recognized: "Congress consciously distinguished between point source and nonpoint source discharges, giving EPA authority under the Act to regulate only the former." Appalachian Power Co. v. Train, 545 F.2d at 1373. See also American Wildlands, 260 F.3d at 1197; Kennecott Copper Corp. v. EPA, 612 F.2d 1232, 1243 (10th Cir. 1979); United States v. Earth Sciences, Inc., 599 F.2d 368 at 371. As discussed in the preamble, EPA believes that following implementation of CAIR and today's action, utility-attributable Hg emissions are not reasonably anticipated to result in hazards to public health.

10.4 TRIBAL TRUST RESPONSIBILITIES

Comment:

Many Indian tribes and organizations (OAR-2002-0056-1327, -1618, -2010, -2118, -2173, -2380, -2694, -2695, -2814, -2891, -3311, -3335, -3413, -3457, -3549, -3550, -3551, -5455) stated that the rule does not comply with EPA's federal trust responsibility, and is inconsistent with EPA's Indian Policy because EPA did not adequately consult with tribes in developing the rule and because the rule does not adequately protect the health of Indians. They assert that tribes have treaty rights to fish, and that the rule does not adequately protect those rights because it does not reduce mercury emissions to a level that protects the health and safety of tribal members who consume fish. They note that EPA's assessment of the risks for tribal members must take into account their high levels of fish consumption, and the unique traditional, cultural, and subsistence importance of fish for many tribes. Finally, some commenters object to EPA's failure to provide for a cap-and-trade program in Indian country.

Response:

EPA recognizes that the Federal government stands in a government-to-government relationship with Federally recognized Tribes and has certain trust responsibilities to these Tribes. This relationship and responsibility should guide EPA in the implementation of policies and actions that affect Tribes. Pursuant to the government-to-government relationship, EPA consults with Tribes regarding actions that affect Tribes. In addition, treaties, statutes, and executive orders create Federal obligations regarding Tribal resources. EPA believes that its actions in developing the final rule have been consistent with the government-to-government relationship and that the final rule itself is consistent with the trust responsibility.

EPA does not agree with the commenters who claim that it did not consult with tribes in developing the rule. As explained in the discussion of EPA compliance with EO in the preamble for the final rule, EPA took the following steps to consult with Tribes. EPA gave a presentation to a national meeting of the National Tribal Environmental Council (NTEC) in April 2001, and

encouraged Tribal input at an early stage. EPA then worked with NTEC to find a Tribal representative to participate in the workgroup developing the rule, and included a representative from the Navajo Nation as a member the official workgroup, with a representative from the Campo Band later added as an alternate. In March 2004, EPA provided a briefing for Tribal representatives, the newly formed National Tribal Air Association (NTAA), and NTEC. EPA received comments on this rule from a number of Tribes, and has taken those comments and other input from Tribal representatives into consideration in development of this rule.

EPA disagrees that the rule will not adequately protect Tribal fishing rights. EPA agrees that some Tribes have unique legal rights to fish arising from treaties, statutes, executive orders, and agreements. EPA also recognizes that Tribal members may catch and consume more fish than the general public as a result of Tribal fishing rights as well as Tribal culture, traditions, and subsistence lifestyles.

EPA believes that this regulation adequately protects Tribal health and is consistent with the trust responsibility for several reasons. First, the commenters understate the significance of the fact that Hg emissions from Utility Units currently are not subject to performance standards. This regulation will for the first time establish performance standards applicable to Hg emissions, and those standards will require significant reductions in the levels of Hg emissions. Such reductions will provide greater protection to Tribal fish resources than would otherwise be available. Acting to provide such heightened protection is consistent with both the statute and the Federal trust responsibility.

Moreover, the commenters offer no specific evidence that the Hg emissions reductions from this regulation will not adequately protect Tribal health. Their main contention is that the regulatory approach set forth in an earlier EPA proposal would have produced a 90 percent reduction in Hg emissions and that any smaller reduction is, therefore, inadequate. That contention rests on a misconception of an earlier Federal Register Notice, which proposed a finding, but did not contain any specific proposal for Hg emissions regulations, and, therefore, did not provide for any percentage of reduction. EPA has never proposed any such rule. EPA believes that this regulation will adequately protect Tribal health.

The commenters also argue that EPA has not adequately considered the significance of Tribal fish consumption patterns, specifically the fact that Tribal fishers consume more fish than the general population. That comment is misplaced. As described in more detail elsewhere in this document, EPA carefully analyzed available information on fish consumption by Tribal members and other sub-populations, and determined how to use the available data most appropriately. One basis for EPA's analysis was a study of tribal fish consumption in one region to model consumption by other Tribes as well as other subpopulations. EPA's approach was to identify areas where the effects of Hg deposition from utility emissions had the greatest effects. EPA then compared those high-deposition areas with locations with high Tribal populations to assess the areas of greatest potential risk to Tribes. That analysis found that very few areas where Native Americans live corresponds with high residual Hg deposition caused by utilities. It found further, that the standards established in the regulation will significantly reduce risks to tribal members.

Finally, as discussed in the preamble to the regulation, this regulation establishes a cap-and-trade program for Indian country.

As part of its analysis of the this final rule, EPA has estimated the some of the health benefits of reducing Hg from utilities. At this time EPA is only able to provide quantitative estimates of the benefits of reducing neurological impacts of exposure to MeHg for a portion of the U.S. population. This population covers people who recreationally catch and consume freshwater fish. The RIA for this rule contains this analysis in Chapter 11. As part of its assessment, EPA provides estimates for the benefits of this rulemaking to subsistence fishers, including case study examples of the benefits to the some members of the Chippewa Tribe, the Hmong, and low income fishers.

10.6 PROCEDURAL ISSUES

Comment:

One commenter (OAR-2002-0056-4132) asserted that EPA was pursuing an inappropriate administrative process, and that the proposal should have been designated an advance notice of proposed rule making (ANOPR). The commenter stated that the proposal was an inappropriate approach to regulatory development and would result in litigation. The commenter stated that affected parties were not being provided an opportunity to comment on the specific regulatory language that might drive significant investments in capital equipment, and characterized the proposal as a menu of possible approaches.

Response:

We disagree with the commenter that the proposed rule constituted an inappropriate administrative process. EPA properly issued a proposed rule in January 2004, and proposed three separate regulatory approaches concerning HAP emissions from Utility Units. In addition, the January 2004 proposed rule and the March 2004 supplemental notice contained proposed regulatory language, and we believe that those proposed regulations, coupled with the extensive discussion provided in the preamble to the proposed rule and supplement notice, afforded the public a sufficient opportunity to comment on the proposed regulatory language. Indeed, EPA received over 500,000 comments on the proposal, about 5,000 of which were unique, and several of which addressed the regulatory text pertinent to the section 111 standards of performance.

Comment:

One commenter (OAR-2002-0056-1138) requested that EPA provide information on the background and training of enforcement personnel. The commenter also requested an estimate of the number of new jobs that are created for every new law or regulation, as well as an estimate of total job growth for the present year.

Response:

This comment has no relevance to how EPA sets standards of performance under CAA section 111, and therefore no response is required.

10.7 GENERAL COMMENTS

Comment:

A large number of commenters, primarily from the general public through individual letters and mass mail campaigns, provided general comment along the lines of:

(1) The proposed rules are a roll-back of the CAA;

(2) The CAA requires 90 percent removal; and

(3) The time-frame proposed for the emission reductions is too long.

Response:

EPA believes that these comments stem, in part, from a misunderstanding of the CAA. There has been no "roll-back" of the CAA. First, EPA does not have the authority to change the CAA (only Congress can do that). Further, there are no current Federal regulations requiring the reduction of Hg or Ni emissions from Utility Units to be "rolled-back." This is the first time that Federal regulations limiting these pollutants have been proposed. In addition, the CAA does not mandate any specific emission reduction. Emission standards are to be based on the level of control achieved in practice and on the level of emission control technologies that the Administrator has been adequately demonstrated. The timing of the emission reductions have been addressed elsewhere in this document.

RESPONSE TO SIGNIFICANT PUBLIC COMMENTS ON THE PROPOSED CLEAN AIR MERCURY RULE

Received in response to:

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 4652; January 30, 2004)

Supplemental Notice for the Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units
(69 FR 12398; March 16, 2004)

Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources, Electric Utility Steam Generating Units: Notice of Data Availability
(69 FR 69864; December 1, 2004)

Docket Number OAR-2002-0056

Appendix A – List of Commenters

US Environmental Protection Agency
Emissions Standards Division
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

15 March 2005

General Outline

Table A-1. List of commenters on the Proposed NESHAP; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units

Docket ID No. OAR-2002-0056	Commenter
0032	Brent A. Tozzer
0033	Ron Kuolous
0090	Mary Patt Garr
0091	Anonymous
0093	Anonymous
0094	Anonymous
0095	Linda Costello
0097	Joseph Traugott
0098	Chris Skidmore
0099	V. R. Sansone
0100	Anonymous
0101	Rosemary Adams
0102[2]	554 mass mailings
0103	Maureen Russell
0106	Anonymous
0109	Sarah Jane Geraldi
0110	Tyler Morrison
0111	B. Kamke
0112	Judith VanDuzer
0113	Anonymous
0114	George Smith
0116	Morgan F. Simmons
0117	Chuckie Walker

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0118[2]	393 mass mailings
0119[2]	5,692 mass mailings
0120	Anonymous
0121[2]	20,056 mass mailings
0122[1]	Ann Pierson
0124	Susan Brown
0125[2]	367 mass mailings
0127	Dr. Lindsay Lafford
0128	Marian M. Pelton
0129	Michele Mukatis
0130	Marion A. Mulholland
0131	Clark James
0132	Clark Andelin
0133	Ruth A. Tallman
0134	Roger Zum
0135	Anonymous
0136	David Stupin
0137	Anonymous
0138	Anonymous
0139	Anonymous
0140	Beth Goldenfield
0141	Chris Sapp
0142	Cindy Beeson
0143	Courtney Weber

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0144	Drew Huening
0145	John Purdy
0146	John O'Leary
0147	Joseph Barrett
0148	Kurt Weiss
0149	Megan Mietelski
0150	Paul Franckowiak
0151	Rebecca Heal
0152	Robert Stein
0153	Stephanie Trick
0154	Tanya Dobbs
0155	Teri Crocket
0156	Terry Hughs
0157	Tom McFarland
0158	Will Bolton
0159	Anonymous
0160	Bill Daugaard
0161	Bob Leggett
0162	Dee Holm
0163	Diana Nihem
0164, 0568	Diane Sklensky
0165	Dorothy Skovholt
0166	Jill Welch
0167	Gabriel Grabin

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0168	Anonymous
0169	Anonymous
0170	Jody Erickson
0171	Judith Englander
0172	Kara Ravenscroft
0174	Karen Johnson
0175	Lia Hutton
0176	Michael Larimore
0177	Paul Chadwick
0178	Peter Raptis
0179	Peter Reynolds
0180	Rabbi Fred Scherlinder Dobb
0181	Roy Johnson
0182	Scott Tobias
0183	Anne Gregory
0184	Anne Hoskins
0185	Christy Chase
0186	Clifford May
0187	Collin Olson
0188	Dean Petrich
0189	Deborah Leiner Fields
0190	Erica Mullen
0191	Gregory Kaplan
0192	Harold McNaron

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0193	James Kaplar
0194	Jeff Fletcher
0195	Jerome Bargo
0196	Margaret Welke
0197	Mary Kaplar
0198	Mary King
0199	Michael Ackerman
0200	Michael Grill
0202	Michael Mauldin
0204	Michael Shapiro
0205	Ravi Grover
0206	Pat Simpson
0207	Robert Shroy
0208	Susan Evilsizer
0209	Suzanne Rosenblatt
0210	Tina Shang
0211	Mike Gravina
0212, 0213	Carolyn Corn
0214	Teresa J. Frakes
0215	Anonymous
0216	Shirley Cook
0217	Matthew English
0218	Kay Brunnier
0219	Lea Siciliano

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0220	Alan Posich
0221	Amanda Richmond
0222	Andrew Rowland
0223	Antonio Cutolo-Ring
0224	David Fox
0225	Gregory King
0227	John Schmidt
0228	Kristen Hannum
0229	Linda Kimberly
0230	Martha Gene Landry-Murphy
0231	Mary Niedermeier
0232	Kevin Naze
0233	Joseph Grinnel
0234	Colleen Spark
0235	Magnus Borgehammar
0236	Carole Pooler
0237	Kevin Pamulak
0238	Marion Sebastion
0239	Paul C. Lee
0240	Catrina Poindexter
0242	Paula Burgess
0243	Priscilla Mattison
0244	Rebecca Goodrich
0245[1]	Anonymous

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0246	Trevor Goodger-Hill
0247	Robert Jarecke
0248	Chuck Watterson
0249	Juliana K. Dulmage
0250	Ruth Dasche
0251	Clyde Hanson, Sierra Club North Star Chapter
0252	Rachael Lindsay
0253	Nina Eichacher
0254	Susannah Nade
0255	Katie Stan
0256	Erin Smith
0257	Timothy Hinkle
0258[2], 0833[2]	Maureen D. Smith, Senior Assistant Attorney General, Environmental Protection Bureau, Department of Justice, New Hampshire
0259	Henry Frank
0260	Jessica Noble
0261	Renee and Larry Stern
0262	James Swaney
0263	Carl Jansen
0264	Jan Saecker
0265	Susan Chandler Schoof
0266	Kevin S. Randall
0267	Sarah Murdock
0268	Sue Howell

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0269	Wanda Ballentine
0270	Adam Fedor
0271	Agnes Kelly
0272	Alex Sproul
0273	Bruce Livingston
0274	Charles Reed
0275	Charles Rinehart
0276	Christin Cifelli
0277	Darius Sivin
0278	Debora Hunter
0279	Derek Mazurek
0280	Ethyl Healy
0281	James Richard
0282	Joel Berns
0283	Kate Cleland-Sipfle
0284	Laura Jobe
0285	Michael Tieman
0286	Roberta Blaylock
0287	Ana Kasa
0288	Scott Bonner
0289	Shaler Stidham
0290	Stephen Goodrich
0291	Tamara Mason
0292	Connie J. Conklin

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0293	Anonymous
0294	Elizabeth
0295	Gary Schmitz
0296	Anonymous
0297	Christopher Blystone
0298	Carl Lowenburg
0299	Carol Harder
0300	Martin Steitz
0301	Rita Pittillo
0302	Geraldine Martinea
0303, 0627	Asbin-Nichols Family
0304	Ellen S. Harring
0305	Hollie A Williams
0306	Richard Kark
0307	Charlotte Brewer
0308	Constance Weidman
0309	Julie Keeling
0310	Victor Leger
0311	Joseph Wilde-Ramsing
0312, 0401[2], 0447	Erick Tirud, Assistant Attorney General, Vermont
0313	Erik Gehring
0314	Julie Wright
0315	Lori J. Rolander
0316	Jim Traweek

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0317	Chuck Meyer
0318	Pam Mentsh
0319	Ellen Howard
0320	Manaune A. Kinzer
0321	Bradley C. Burwith
0322[2]	Gerald D. Reid, Assistant Attorney General, Maine
0323	Lydia Garvey
0324	Robert I. Miller
0325	Marcia Higgins
0326	Stew Hopkins
0327	Elizabeth Rhodes
0328	Bettie Minette Cooper
0329	Lucille E. Bowen
0330	David Zeff
0331	Cedar Barston
0332	Fern S. Katz
0333	Phyllis Barnister
0334	Anonymous
0335	Anonymous
0336	Paul Debreczeny
0337	Anonymous
0345	Deborah Stirling
0346	Patrick Bosold
0347	Anonymous

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0348	Anonymous
0349	Oscar Shirani
0350	Peter S. Raab
0351	Joshua Saks
0352	Anonymous
0353	Anonymous
0354, 0355	Arthur H.
0356	Anonymous
0357	Troy Kimmel
0358	Rachel Cogen
0359	Paul Piersma
0360	John Kloetzel
0361	Henry Frank
0362	Anthony Ciranna
0363	Joanna Whitlow
0364	Brenda Lillis
0365	Julie Snibel
0366	Judy M. Judd, Professor
0367	Joseph and Yvonne Hammerquist
0368	Karen Mills
0369	Mark Meraner
0370	Robert Sims
0371	Renee Dolney
0372	Albert Davis

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0373	Rachel Herbener
0374[1]	Bobbie Dee Flowers
0375	Karen De Boer
0376	Alternate Energy Group, Indiana University of Pennsylvania
0377	Mary Stadel
0378	Helen Neville
0379	Anonymous
0380	Audrey Adams
0381	Norm Anderson
0382	Anonymous
0383	Christina Pogoloff
0384	Jerry Stifleman and Tracey Oliveto
0385	E. Mark
0386	Susan Anderson
0387	Gayle Stark
0388	Leila Evelev
0389	Charlotte Brewer
0390	Vince Deur
0391[2]	Glen Compton
0392	Anonymous
0393[2]	Michael Logsdon
0394	Julie Bushey Trevor
0395	Leigh Loftin
0396	Doug Viner

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0397	Lynn Bauer
0398	Michael Wexler
0399	Charlotte Trolinger
0400	Robert McGuigan
0402	Anna Keyzers
0403	Eric Weis
0404	Rev. Ilse Peetz
0405	Barbara Greene
0406	Karl Volk
0407	Doris Marshall
0408	Harry Gushikuma
0409	Alice T. Day
0410	Irene Hayes
0411	William A. Collins
0412	Faye F. Shaw
0413	Robert and Helen Lane
0414	Judith T. Hickson
0415	Osmond Molarsky
0416	Laura Kay Collins
0417	Harry S. Hinch
0418	Nancy L. Cook
0419	Dr. and Mrs. G. S. Gilchrist
0420	Zora Klein
0421	M.T. Brace

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0422	Sister Virginia Fabilli
0423	John W. Slocum
0424	Elizabeth Candels
0425	Helena Stone
0426	Janet C. Tillotson
0427	Frances W. Stevenson
0428	Deborah McNeil
0429	Anonymous
0430	Gordon Mallett
0431	C. Watton
0432	Anonymous
0433	Anonymous
0434	Amy Tidd, Sierra Club Turtle Coast
0435	Anonymous
0436	Tia Goss Sawhney
0437	Richard Dickens
0438	Daniel Herzberg
0439	Mark Lindquist
0440	Matthew A. Schwab
0441	Larry Lambeth
0442	Judith Hickson
0443	Mark Doppke
0444	Michael Hayes
0445	Henry Frank

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0446	Peter Hess
0448	Ronald Moore
0449	Randall Rust
0451	Anonymous
0452	Stu Slote
0453	Anonymous
0454	John Haigis
0455	Dan Hobert
0456, 0457	Karen Philhower
0458[2]	25 mass mailings
0459[2]	144 mass mailings
0460	Nathaniel Hart
0461	Ken Whitton
0462	Amy Simmons
0464	Paul Weihe
0465	Rebecca Clark
0466	Peter Glick
0467	Kathy Finch
0468	Robert Ewing
0469	Susan Hammond
0470	Daniel Faust
0471	Clairvaux McFarland
0472	Gary Schmitz
0473	Keith Law

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0474	Francis Wolf
0475	David Harris
0476	Therese Curtis
0477	Anthony Hinrichs
0478	Erik and Dee Voldal
0479	Terri Allen
0480	Anonymous
0481	Andrew Moss
0482[2]	103 mass mailings
0483	Karl Volk
0484	Bonnie Dugan
0485	Judi Friedman
0486[2]	2,223 mass mailings
0487[2]	167 mass mailings
0488	Jan Meyers
0489	Andrew Hudson
0490	Karin Westdyk
0491	Paul Moss
0492	Callie Lowenstein
0493	Ellen Tanner
0494	Doug Viner
0495	Andrea Medaugh
0496	Juliet Rynear
0497, 0499	Anonymous

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0498	Paul Knutson
0500	Pamela Sprague
0501	Gary Stewart
0502	A.J. Ralls
0503	Lynn Bauer
0504	Leigh Loftin
0505	Michael Wexler
0506	Daniel Lambert
0507	Anonymous
0508	Raymond Coulombe
0509	Anonymous
0510	Vincent and Vinita Burns
0511	David Manni
0512	Lela McNutt
0513	Stephen Volkmer-Jones
0514	Bryan Wyberg
0515	Marian Cooley
0516	Anonymous
0517	Karen Green
0518	Priscilla Mcaneny
0519	Fred Carr
0520	Jonathon Lotz
0521	Linda Keller
0522	Peter Davis

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0523	Peggy Bridgman
0524	Naomi Warner
0525	Renetta Balzer
0526	Elisabeth L. Gray
0527	Robert Arnold
0528	Dan Magee
0529	Miriam Mulder
0530	Lora Lumpe
0531	Wallace M. Elton
0532	Randy Schutt
0533	Mark Giese
0534	Rachel Dolney
0535	Howard Holt
0536	Anne Lauren
0537	Mary Love
0538	Amy McClellan
0538, 1808	Ginny Dudek, Physicians for Social Responsibility
0539	Desiree Tullos
0540	Timothy Nakayama
0541	Pamela Burt
0542	Amber Aerts
0543	Albert Weinhardt
0544	Joseph Siperstein, President, Ohio Lumex Company
0545	Celiste Felciano

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
0546	Lauren Demore
0547	Roy Corr
0548	Mike Turner
0549	Martin and Anne Steitz
0550	Gerald DeMaire
0551	Ann White
0552	Neil Robinson
0553	Will Tuttle, Ph.D
0554	Ann Bausch
0555[2], 0821[2], 1608[1], 3448, 3449, 3466, 3488, 3489	William O'Sullivan, Director, Division of Air Quality, New Jersey; Bradley Campbell, Commissioner, New Jersey Department of Environmental Protection
0556	Joseph Barr
0557	Marjorie Derrick
0558	Barbara Lubasch
0559	Susan Bolgiano
0560	Martha D. Austin
0561	27 mass mailings
0562	George J. Rosenbilt
0563	Cheryl Hammond
0564	Henry Frank
0565	Frank Purcuinelli
0566	Kevin R. Jones
0567	Ted Sowinski

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0569	Chris Weston
0570	Bob Newgard
0571	Audrey Seymour
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0573	Graham Stafford
0574	Mary E. Bolton
0575	Keri Smith
0576	Bonnie Hart
0577	Dave Mellinger
0578	Cheryl Gross
0579	Ann Isaksen
0580	Michael D. Conlon
0581	Peter Steinhart
0582	Richard Hay
0584	Debra Kirchhof-Glazier
0585	William R. Thompson
0586	Bart
0587	Arvia E. Morrow and Peter Clitherow
0588	Diana Olhbaum
0589	Michael Brown
0590	Vincent Bowers
0591	Trevor Swoverland
0592	Jay Starkey

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0594	Anonymous
0595	Wolfgang Rougle
0596	Chandlee Dickey
0597	Joel and Linda Morris
0598	Bruce Nesmith
0599	Sean M. Dee
0600	Sarah Curry
0601	Nita Ferguson
0602	Bill Potter
0603	Paul Fell
0604	Steve Freedkin
0605	Katelyn Perry
0606	Lynn Weintraub
0607	Lauretta Lange
0608	Julian Powers
0609	Mary A. Simpson
0610	Erin Maloney
0611	Amanda Behrens
0612	John Amadio
0613	Diane Walker
0614	Elizabeth McSweeney
0615	Teresa G. Lyons
0616	Heather Aston

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0618	Marie Mallin
0619	Nick Lutz
0620	Mario Solis
0621	John McGruder
0622	968 mass mailings
0623	451 mass mailings
0624	Agnieszka Pinette
0625	220 mass mailings
0626	10 mass mailings
0627	Asbin-Nichols Family
0628	Anne Haug
0629[2]	2 mass mailings
0630[2]	13 mass mailings
0631	Robert S. Wallerstein
0632	Eartha Newsong
0633, 0634	Robert S. Freeman
0635	Tam H. Greene
0636	Carl and Robyn Campbell
0637	Anonymous
0638	Scott Newman
0639	Anonymous
0640	Anonymous
0641	Anonymous

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0643	Paul D'aura
0644	Richard Gilman
0645	Steve Knockemus
0646	Kim Struyk
0647	Anonymous
0648	Moira Smullen
0649	Indra N. Frank, MD
0650	Michael Brown
0652	William S. Bike
0655	Sue Travis
0658	Bob Fehribach
0659	Michael Vinciquerra
0660	Melissa Klein
0661	Connie Hohfeld Molbeck and James E. Molbeck, Jr.
0662	Sarah Curry
0663, 0664	Myrtle H. Cox
0673	Judy Thornber
0675	Susan Troxell
0678	Glenn Luba
0679	Donald R. Cumming
0681	Mike Shackelford
0682	Cheryl Casker
0684	Gaston Locklear

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0687	Elizabeth Geiger
0688	Jay Byrnes
0689	Kristie Turnbaugh
0690	Mary Hoffman
0691	Ronald and Sara Wenda
0692	Barbara M. Parramore
0693	Michael Riggs
0694	Chris A. Stockner
0695	Lee Meyers
0696	Scott Fisher
0697	John Maheu
0698	Dean Petrich
0699	David Carek
0700	David Brown
0701	Kathy Finch
0702	Jenny Ball
0703	Mary C. Voltaggio
0704	Joan Candalino
0705	Judith Green
0706	Douglass Gerleman
0707	Bobbie Dee Flowers
0708	Phil Medeiros
0709	Dan Keifer

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0711	C.J. Clawson
0712	Wing Goodale
0713	Jeri Mueller
0714	David Smolinsky
0715	Richard Robertson
0716	Craig Havens
0717	Ken Reynolds
0718	Anonymous
0719	Richard and Evelyn Avery
0720	Low Taylor
0721	Denise Kelley
0722	Chloe Curry
0723	Niall Stephens
0724	Mary Celeste Reese
0725	Sharon Labelle
0726	Liz Cullington
0727	Debbie Netardus
0728	Barbara Leibundguth
0729	Mary Daily and Household
0730	Gail Marie Chester
0730, 1566, 1670	N. Marcia Jimenez, Environmental Commissioner, Chicago
0731	Gary S. Entre
0732	Joanna Willimetz

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0734	Curtis T. Fowle
0735	Dona M. Baba
0736	Joane Dunhill
0737	Trisha Woolcott
0738	Sharon E. Cody
0739	7 Connecticut citizens
0741	Sherwin Sharan
0742	Jan Garton
0743	Kate Beckwith
0744	Laverne Briscoe
0745	Marjorie Homza
0746	Kenneth LaFord
0748	Virginia Booz Ullrey
0749	Lynn Darling, Audubon-Sierra Club-Nature Conservancy
0750	Monica Moore
0751	Barry Fahrer
0752	John Orr
0753	Lorraine Gentz
0754	Carlos Hernandez
0755	Robert Ross
0756	Joe Peter Burton
0758	Mary Jo Manley
0759	Nancy Lev

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0761	Ernesta Kraczkiewicz
0762	Kristin Kavanagh
0763	William K. Simeral, Sierra Club
0764	George Sorvalis
0765	Richard Fitzpatrick
0766	William Curtis
0767	Daniel Flasar
0767	Daniel Flasar, Washington University School of Medicine
0768	Martin Wallace
0769	Ettus Hiatt
0770	Pete Wilson
0771	Wendy Noel Frederick
0772	Mark Doppke
0773	Dolores Tippett
0774	Erin Moore
0775	Jean Hill-Pond
0776	Vivian Bergstedt
0777	H. V. Harris
0779	Corinne Higbee
0780	Richard H. Davis
0781	Gail Stewart
0782	Mike and Ellen Dale
0783	Phil Krenz

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0785	Barbara Zaroff
0786	Nathan Herald
0787	Dan Burton
0788	Beth Belanger
0789	Jim Slaughter
0790	J. Perino
0791	Lillian Lageyre
0792	Frank McMahon
0793	Suzanne Connolly-Howes
0794	Joaquin Sapien
0795	Carol Stroebel, Friends of the North Fork Shenandoah River
0802	Glenn Parsons
0803	Dorothy Blaustein
0804	Nancy Rogers
0805	Brad Currier
0806	Jerry Goodman
0807	Nancy Hale
0808	Jim Hale, Sierra Club
0809	William Haines
0810	Marliss Rogers
0811	David
0812	David Kass
0813	Betty Leech

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0815	Matthew Olsson
0816	Carol Else
0817	J.K. Reynolds
0818	M. Wilson
0819	Dolores Rodriguez
0820	John Walliser
0822	Rebecca Kurowski
0823	Inga E. Thompson
0824	Robert C. McMurray
0825	Diane Schroeder
0826	Evan Martin
0827	Teresa Smigelski
0828	William J. Schultz
0829	Dale Whorl
0830	Patricia Michael
0831	Chris Weehler
0832	Frances Freewater
0834[2]	Bill Richardson, Governor of New Mexico
0835	Hildegarde Hannum
0836	Diane J. Peterson
0837	Anthony H. Hinrichs
0838	Bonno Bernard
0839	Hedi Gerson

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0840	Catherine O'Connell-Cahill
0841	Scottie Foerber
0842	Glenys Spitze
0843	John Castronavo
0844	Rosalind Michahelles
0845	Susan Dianne Rice
0846	Leonore Johnson
0847	Liz Mills
0848	Adam Lifter, Environmental Defense Action Fund
0849	Stan Baker
0850	Judith Lockwood
0851	Paul A. Kotta
0852	Caroline Getz
0853	Judith E. Fletcher
0854	Alan Richmond
0855	Troye Kauffman
0856	Harriet Wright
0857	V.S. Clay
0858	Frank Capparelli
0859	Debra Ovadia
0860	Rev. Cynthia Crowner
0862	Charles T. Phillips
0863	Anonymous
0864	Tina Holzer

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0865	Margaret Chenoweth, Spirithaven Foundation Inc.
0866	Julia Zaslow
0867	James L. Folz
0868	Ann Reed
0869	Don J. McCrery, Sierra Club, Coulee Region
0870	Christine Danyi
0871	Wendy Colschen, Sierra Club, Coulee Region
0872	Lauren Steiner
0873	Dirk and Elizabeth Faegre
0874	Walter Hamilton
0875	Jeanne Forbes
0876	Don Morgan
0877	Devin Post
0878	Renate Brown
0879	Michael Weissman
0880	Alice
0881	Mary McCurnin
0882	Norma Eppinger
0883	Roxanne Boyle
0884	Calvin Lindsay Elmendorf
0885	Michael A. Rubin
0886	Leo Stack
0887	Stanley Grossel
0888	Kenneth R. Schmidt

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0889	Nanette Nelson
0890	Nancy Solomon
0891	Sue Nattinger
0892	Evan Colletti
0893	C. L. Spray
0894	Patricia Etue
0895	Anne Kaufhold
0896	Lisa Printz
0897	Barbara Seidel
0898	Roger Southworth
0899	JoAnn Durfee
0900	Sheryle Pettet
0901	Vitaly Volmensky
0902, 0956	Lance Joseph Marietta
0903	Loretta Van Coppenolle
0904	Julia Sapir
0905	Di Ana Marcus
0906	Joan W. Montagne
0907	Linn D. Barrett
0908	Anonymous
0909	Anonymous
0910	Armand C. Hale
0911	Anonymous
0912	James Luth

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0913	Anonymous
0914	Anonymous
0915	Robert L. Anderson
0916	Arlene Howell
0917	Anonymous
0918	Cynthia Clayton
0919	Harold Stevens
0920	Kim Rangel
0921	Anonymous
0922	Anonymous
0923	Joseph A. Valastro
0924	Joseph Breeden
0925	Anonymous
0926	Raymond Zachary
0927	James Shaw
0928	Anonymous
0929	James Boone
0930	Jim and Gail Richardson
0931	Ken Sher
0932	Stephen Potter
0933	Anonymous
0934	Dick Wright
0935	Kenny Schultz
0936	Anonymous

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0937	Glen Ehnert
0938	Sandi Steidley
0939	David Fiel
0940	James Windholz
0941	Siegel L. Junker
0942	Rick Sealander
0943	Malcolm R. Innerarity
0944	Anonymous
0945	Jayson A. Alteiri
0946	Carol M. Shelton
0947	Jerry Willner
0948	Bruce Youngbert
0949	Anonymous
0950	James R. Brunner
0951	Anonymous
0952	John, Sherry, and Jonathan Swanson
0953	Mr. and Mrs. Richard L. Smith
0954	Brenda Ballard-Ream
0955	Joe Metzinger
0957	David J. Booth
0958	Arthur Meader
0959	Anne Beaumont
0960	David Cayford
0961	Lisa Perrine

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0963	Bruce Robertson
0966	Azel Beckner
0969	Marni Nacheff
0974	Eugenia Stoddard
0976[2], 1624, 1801, 1775, 1863, 2871	James A. Joy III, President, STAPPA; Cory Chadwick, President, STAPPA/ALAPCO; Brock Nicholson, STAPPA/ALAPCO; Joyce E. Epps, STAPPA/ALAPCO; Sandra Ely, STAPPA/ALAPCO; James A. Joy, President, STAPPA and Dennis J. McLerran, President, ALAPCO
0978	Dana C. McGuire
0979	David Evans
0980	Margaret Peacock
0981	Marge Johnson
0982	Leo Beers
0983	Clara Blair
0984	Lindsay Lafford
0985	Andrew Lenz
0986	Audrey Schulman
0987	Anonymous
0988	Vicky R. Peterson Howell
0989	John Eakins
0990	Mary Ellen Rozmus
0991	Christopher Warren
0992	Anonymous
0993	Anonymous
0994	Anonymous

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0995	Tracy Petitjean
0996	Phillip Higley
0997	Vernon Kuhns
0998	David Siegel
0999	Bill Levin
1000	James Quinn
1001	Pamela Tabor
1002	William Johnson
1003	James Huntsman
1004	Brad and Bernice Pohlmann
1004	Carl E. Venne, Chairman, Crow Tribe of Indians
1005	Gus Beall
1006	Ronald Thompson
1007	Allen Brooks
1008	Sharon Fox
1009	James Woodruff
1010	Lance C. Lane
1011	Diane Dempsey-Shiber
1012	Bob Golenkow
1013	Sherry Salomon
1014	Anonymous
1015	James Dryer
1016	Anonymous
1017	Anonymous

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1019	Robin Trellis
1020	Anonymous
1021	Martha A. Pitts
1022	Anonymous
1023	Greg Mitchell
1024	Dallas Snyder
1025	Anonymous
1026	Tracy Keiper
1027	Grace Gomez
1028	Edward S. Quest
1029	Mark Stewart
1030	Carl Bundy
1031	Joseph DiMarco
1032	James Brook
1033	Tucker Ruberti
1034	Richard E. Brown, American Veterinary Medical Association
1035	Brian Forrest
1036	Michael J. Murtha
1037	Janice H. Shawl
1038	Anonymous
1039	Katie Griffin
1040	Evelyn Nichols
1041	Nat Thompson

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1043	Anonymous
1044	Anonymous
1045	Anonymous
1046	Anonymous
1046	Ed Lone Fight, Crow Tribe
1047	Anonymous
1048	Anonymous
1049	James Dearmore
1050	Arlene H. Wieland
1051	Mary Gutzwiller
1052, 1053	Rudy Lehle
1054	Elizabeth Piner
1055	Milla Kette
1056	Anonymous
1057	Raymond Herrmann
1058	Dott Clarke Koch
1059	Doug Farnen
1060	D. Murphy Hunt
1061	Paul Calabrese
1062	Donald E. Basse
1063	Shawn Branch
1064	Izzy Marrone
1065	Mary Bowen

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1066	Anonymous
1067	Pete Gandy
1068	Lynn Silvernale
1069	Bill Hampton
1070	Anonymous
1071	Anonymous
1072	Thomas Houser
1073	John De Nicola
1074	Scott W. Witten
1075	Tim Peplaw
1076	Anonymous
1077	HiAnonymous
1078	Ken
1079	Bill Cook
1080	Joe Nemecek
1081	Anonymous
1082	Anonymous
1083	Jeanette Strother
1084	Edna Crews
1085	Anonymous
1086	Jeanne Schmelzer
1087	Randel Bradley
1088	Marie Michael
1089	Robert Charles Duffey

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1091, 1092, 1093	Janis Starkman
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1095	Steve Trebus
1096	Agnes and Len Tillerson
1097	Anonymous
1098	Richard Wahl
1099	James V. Cole
1100	Mikel W. Conner
1101	R.M. Tambascio
1102	Zane Withrow
1103	Robert Stockman
1104	Theodore E. Bruszewski, Phd.
1105	Rod Brace
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1107	Anonymous
1108	Anonymous
1109	Matthew Anderson
1110	Douglas Meyer
1112	Dee Anderson
1113	Steve Bazon
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1118	Richard Blain
1119	Whitney Wiggins
1120	Richard Ressler
1121	Donna Warner
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1123	Joe Bartlett
1124	Mary Newnum
1125	Lindsay McMillan
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1128	Barbara L. Redi
1129	Deborah Oberbillig
1130	Jim Sollars
1131	Betty Bains, Sierra Club
1132	Seth Rolland
1133	Julie Patten
1134	Allen and Juanita Ward
1135	Anonymous
1136	Hannah Reinhart
1137	Walt Oicle
1138	Jeff Jackson, Center for Advanced Research and Technology
1139	Christine Clayton
1140	Jennifer Shroder

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1142	Jane Freij
1143	E.J. Cheshire
1144	Fran Daggett
1145	Joyce Wilson
1146	Raymond Leon Currier
1147	Grace Pasquarello
1148	Anne Baskin
1149	Stephanie Lafontaine
1150	Percy Lilly
1151	Julie Denision
1152	Robert Gumlock
1153	Ora Lee Young
1154	Beatrice Stone
1155	Theresa Jaworowski
1156	Susan Shouse
1157	Michael Gallaway
1158	Holly Robbins
1159	Bess M. Greenfield
1160	Kimball Hugh Bradshaw
1161	Robert L. Milne
1162	Maxine A. Dalton
1163	David B. Patterson
1164	James P. Beck

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1166	Peter Taylor
1167	Sharon Cunningham
1168	John P. Bucki
1169	Diane M. Long
1170	Charles Carter
1171	Moira Smullen
1172	Mel Williams
1173	Paul Cowden
1174	Kate Merrick
1175	Pamela Lundquist
1176	Alan Arqueza
1177	K. V'Spek
1178	Stephen Carey
1179	Connie Golisano
1180	Paul Averill Liebow
1181	Joseph Ponisciak
1182	Fred and Cheryl Heinecke
1183	John Rogalski
1184	Matt Jorgensen
1185	Kelly P. Coleman
1186	Natalie Keiser
1187	Tim Bryson
1188	Deb Coyle

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1191	Wendy A. Parda
1192, 2448	Brian Cladoosby, Chairman, Swinomish Tribal Community
1193	Jeff Ruch, Public Employees for Environmental Responsibility
1194	Julia R. Lassotovitch
1195	Janice Patterson
1196	Alan J. Benedict
1197	Deborah D. Stewart
1198	Lee Marinaccio
1199	Erik T. Rotto
1200	Rikki Enzor
1201	Evelyn Vetere
1202	Christine M. Hicks
1203	Larry Bogo
1204	Natalie B. Killeen
1205	Sanford Gottlieb
1206	Shirley Bandy
1207	Molly McCoy Straus
1208	Cecil Lubitz
1209	Debby McMillan
1210	Colter McCorkindale
1211	Joe Stocken
1212	Lee Martin

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1214	Craig Schwnerman
1215	Jackie Howe
1216, 1229	Kimberly Carter, MD
1217	Annaka Larson
1218	George T. Riley
1219	Gary Botzek
1220	Mark Johnson
1221	James R. Wilson, M.D.
1222	Eric A. Sartori
1223	Rachel C. Baultinghause
1224	Joanne L Jacobson and Stuart Riches
1225	Mha Atma S. Khalsa
1226	John C. Haas
1227	Tammy de Sola
1228	James W. McMekin
1230	Joseph James
1231	Jyllian Smolev
1232	Henrietta L. Wiley
1233	Debbie Netardus
1234	Monastery of St. Gertrude
1235	Mr. and Mrs. Lance Hartford
1236	Anonymous
1237	J.D. Nesbitt

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1240	Thomas Heisey
1241	Michael Kunz
1242	William E. Fisher, Jr.
1243	Anonymous
1244	Donald Estrada
1245	Suzie Clay
1246	Sharon Smith
1248	Renee Evanoff
1249	Kimberly A. Marusshok
1250	Patricia A. Hogan
1251	Ronald Gombach
1252	Gary Matson
1253	John Hanus
1254	Brad Shepard
1255	Matthew Pavolka
1256	Nancy Sohn
1257	Gayle Stark
1258	Marlene Renwyck
1259	Daniel P. Fischer
1261	Weavers Way Cooperative
1262	Holly Earnest
1263	Justin Burke Walsh
1264	Margaret Yaggie

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1266	Denise Bash
1267	Scott Brown
1269	George Clements
1273	Scott Lewis
1274	Karen Bosc
1275	Susan H. Cushman
1276	Jim Fronk
1277	Sheryll Perry
1278	Amy Stuckey
1279	Mike Thompson
1280	Jimmy W. Hosch, Ph.D.
1281	Mary V. Hull
1282	Donna Eyman
1283	Daniel Heyduk
1284	Rachael Dillman
1285[1]	Lucille Nurkse
1286	Dinda Evans
1287	Paul G. Rubin
1288	Karen Bright
1289	Carol L. Schneider
1290	Dolores Hazlebeck
1291	Bruce Hogan
1292	Susan A. Pohl

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1294	Sandra R. Fackler
1295	Cynthia Radcliffe
1296	Robert Fener
1297	Louise Poulter
1298	Ellen Fauerbach
1299	Christopher Kearney
1300	Steven Gehman
1301	Andrew Mongeon
1302, 1303	Brian Chisdak
1304	Diana Danford
1305	Debra, Kenn, and Raina Duncan
1306	Dr. P.M. Schlosser
1307	John Engh
1308	Robert Kulp, Jr.
1309	Lindsay Holliday
1310	Heather Soloman Wright
1311	Anonymous
1312, 1617	Ajay Goyal, SASY Inc.
1313, 1315	Carol Stark, Citizens Against Ruining the Environment Ellen Rendulich et al., Citizens Against Ruining the Environment
1314	Anonymous
1316	Jessica Woodward
1317	John Mulhall

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1318	David Vaughan
1319	Geoffrey Taylor
1320	Alfred and Mary Jane Hasemeier
1321	Peter Todd
1322	Joan Hooker
1323	Hoyt Johnston
1324	John Lambert
1325[2]	Jody Lanier
1326	Rev. Virginia Brown
1327	Robert Peacock, Chairman, Business Committee for Band of Lake Superior Chippewa
1328	David S. Baskin, M.D.
1329	Bradley Robert Dean
1330	Linda Ewald
1331	Lydia Garvey
1332	Dr. and Mrs. Gilchrist
1333	Steve Hopkins
1334	Victor Leger
1335	Chuck Meyer
1336	Kaaren Mills
1337	Reevis and Joanna Scott Picher
1338	Holly Williams
1339	Anonymous
1340	Thomas Kardos

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1341	Timothy W. Ames
1342	Theresa Hutchins
1343	Anonymous
1344	Inese Holte, TOXIC
1345	Anonymous
1346	Woodfin Bauer
1347	Joseph Holtzman
1348	Anonymous
1349	George W. Schnabel
1350	Anonymous
1351	Anonymous
1352	Wendy Smith
1353	Anonymous
1354	Anonymous
1355	Ann Waterhouse
1356	Anonymous
1357	Anonymous
1358	Anonymous
1359	Scott and Laura Helgeson
1360	Tim Schumann
1361	Tasha Waldron
1362, 1363	Julie Gagliano
1364, 1365	Erich C. Morris
1366[1]	Anonymous

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1370	Carol Dalrymple
1371	Anonymous
1372	Kent Brooks
1373	Kathryn Canetti
1374[2]	Frances H. Clark
1375	Christopher Clark
1376	Melanie Clements
1378	George Cavros, Sierra Club/Broward County
1402	Sarah Martin
1403[2]	Rachael Mason
1404	Ronald Matt
1405	Pam Menish
1406	Jean D. Messina
1407	Dave Momenee
1408	Phyllis Smith Nickel
1409	Marie Olasov
1410	Karen O'Neil
1411	Janee P. Peters
1412	Loretta Papaulla
1413	Ralph G. Pound
1414	Jesse Powers
1415	Marcia L. Reiter
1416	Kathleen Rospenda

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1417	Kristina Schiermeister
1418	Phil Scott
1419[2]	Gloria and Leo Seigel
1420	1,420 mass Sierra Club/Mackinac Chapter mailings
1421	C. Stancioff
1422	Rachel Strasz
1423	Sarah A. Sweeny
1424[2]	John Terrell
1425	Rachel Thompson
1426	John Tsingas
1427	Anonymous
1428	Anonymous
1429	Issac Vas
1430	Robert Weinberg
1431	Stephen Wells
1432[2]	Catherine and Paul Williams
1433	J. Woods
1435	Jim Stoll
1436	Paul Kangas
1437	Munsom
1438	Vinita and Vincent Burns
1439	Mary Brenneman
1440	Trisha Wollcott
1441	Dorothy Wolf

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1442	Ruth V. Steen
1443	J.K. Reynolds
1444	Gail Marie Chester
1445	Carol Else
1446	Glenys Spitze
1447	David Zeff
1448	Susanne C. Jessen
1449	V.S. Clay
1450	Catherine O'Connell-Cahill
1451	Elizabeth J. and Luther R. Candels
1452	M.T. Brace
1453	Laura Kay Collins
1454	Sister Rita Mary Olszewski
1455	Celeste Felliano
1456	Kay Brunnier
1457	Robert and Helen Lane
1459	Anonymous
1466	Anonymous
1467	Anonymous
1468	David Schuster
1469	Kathy Altf
1470	Bob and Ellen Lempera
1471	Susan M. Collins, U.S. Senate
1472	Karen L. Keller

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1473	Dan De La Forest
1474	Gregory Fix
1475	Phyllis Arthur, President, County Commission of Mason County
1476	Paul Mack
1477	Wren Osborn
1478	Matt Stringer
1479, 1740, 3262, 3562, 3333	Peter Heed, Attorney General, State of New Hampshire for Attorneys General and Chief Environmental Enforcement Officers for 12 States
1480	Sidney Wanzer, M.D.
1481	Constance and David Williams
1482	Ollie Harvey, Mayor, City of Ripley, West Virginia
1483	Richard Milam, Mayor, City of St. Albans, West Virginia
1484	Amy Bidwell
1485	Anthony Shoberg
1486	Tracy Plombon
1487	Frances Lamberts
1488	Elizabeth Bouma Holtrop
1490	Jamie Chichering
1491	Jack Saye
1492	Marion Sirefman
1493	Jonathan Parfrey, Physicians for Social Responsibility
1494	Jill Jensen
1495	Marsha Pernat
1496	Senja Lopac

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1497	C. Geri
1498	Erica Voss
1499 , 3206, 34290	Barry Stemshorn, Assistant Deputy Minister, Environment Canada; Sierra Legal Defense Fund (Canada)
1500	Praveen Gonugunta
1501	Mary Zabinski
1502	Sunshine Willard
1503	Violet Stark
1504	Marion J. Aherne
1505	Wayne Martin
1506	Anonymous
1507	Anonymous
1508	Anonymous
1508	Bernard Windham, Dental Amalgan Mercury Syndrome
1509	Sue Vernier
1510	H.M. Jones
1511	Anonymous
1512	Anonymous
1513	Anonymous
1514	Anonymous
1515	Anonymous
1516	Vasilios Contis, et al.
1517	Jay Snodgrass
1518	S.L. Horton

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1519	Martin Vongrej
1520	Bill Pielsticker, Chair Wisconsin Council of Trout Unlimited
1521	Anonymous
1522	John M. Wiggins
1523	Anonymous
1524	Eindall K. Stine
1525	Anonymous
1526	Harvie Beavers
1527	Anonymous
1528	Stephen Miller
1529	Arnold Staloff
1531	Joan Patterson
1532	Lisa S. Qualls
1533	Dee Ann Diedrich
1534	Beth Judy
1535	Michael Solomont
1536	William Menghi
1537	Anonymous
1538	David Armstrong
1539[3]	Thomas Keller, PPL Services Corp.
1540[2]	Kimberly Massicotte, Assistant Attorney General, State of Connecticut
1541	Anonymous
1544	Lisa Beebee
1547	Gabriel Ruijsenaars

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1551	Nita Garber
1552	Benjamin Heine
1553	Trout Unlimited, Blue Ridge Chapter
1554	Anonymous
1555	Steven Heiskary, North American Lake Management Society
1556, 1557, 1558	Anonymous
1559	Anonymous
1561	Janis Peters
1562	Anonymous
1563	Anonymous
1564	Thomas M. Krauskopt
1565	Anonymous
1567, 1568	Dick Salonek
1569, 1571	Richard D. Carvajal, M.D.
1570	Jocelyn A. Ziemian
1572	Anonymous
1573[1]	Anonymous
1574	Anonymous
1575	T.H. Crawford
1576	Anonymous
1577	Anonymous
1578	Larry Varnell
1579	Clayton Bollin
1580	Anonymous

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1581	Anonymous
1582	Cathy Mihaly
1583	Robert M. Keliher, The Calumet Ecological Park Association
1584	Gerald J. and Ruth J. Moyar
1585	Sara L. Bein
1586	Jeremy Green
1587	Jennifer Kothlow
1588	Jonathon Osmond
1589	Robert O. Preyer
1590	Sandra Spendlove
1591	Ramona Finos
1592	Janice Owens
1593	Marta Taylor
1594	Willi Lehner
1595	Karen L. Keller
1596	Brandt Mannchen, Sierra Club/Houston
1597	Nelson H. Hawkins
1598	Bruce Hooke
1599	Becky Lee, et al.
1600	Nancy Thompson
1601	Anonymous
1602	Mr. and Mrs. Americo A. Fusco
1606[3]	Ajay Goyal
1606[3]	Ariele Llorens

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1606[3]	Bill Moore
1606[3]	Blayne Grave
1606[3]	Brian Urbaszewski, American Lung Association
1606[3]	Caroline Herzenberg
1606[3]	Coleen Sarna
1606[3]	Dave Madden
1606[3]	David Hetzel
1606[3]	David Cugell, M.D.
1606[3]	Donna Green
1606[3]	Edward Haggard
1606[3]	Elaine Kittredge
1606[3]	Erin Jorhadl-Redin
1606[3]	Gina Lettiere
1606[3]	Ginger Duiven
1606[3]	Indra Frank
1606[3]	Jackie Schomer
1606[3]	Jacob Zausch
1606[3]	Jill DeWitt
1606[3]	Joan Para
1606[3]	Joe Highland
1606[3]	Johathan Parfrey, Physicians for Social Responsibility, LA
1606[3], 1632	John Heinrich, Wisconsin Department of Natural Resources; Henry Anderson, Wisconsin Department of Health and Family Services
1606[3]	John Raffensperger

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1606[3]	Julia Allison Risser
1606[3]	Kim Novick
1606[3]	Kristi Kowal
1606[3]	Laura Urbaszewski
1606[3]	Lauren Mansell
1606[3], 1665	Lee Francis , Physicians for Social Responsibility
1606[3]	Lee Foushee, Indigenous Womens Mercury Investigation
1606[3]	Lisa Diment
1606[3]	Lisa Yee
1606[3]	Margaret McClintock
1606[3]	Marjorie Ettlinger, League of Women Voters
1606[3]	Mary Holms
1606[3]	Michael B. Kaye
1606[3]	Michael Grill
1606[3]	Michael B. Kaye
1606[3]	Michael Brill
1606[3]	Michele Sommers
1606[3]	Michelle Navarre Cleary
1606[3]	Pat Guinn, Lt. Governor, State of Illinois
1606[3]	Patty Crow
1606[3]	Rebecca Winkler
1606[3]	Roberta Richardson
1606[3]	Roger Grissette
1606[3]	Sandra Benzeev

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1606[3]	Shannon Fisk, Environmental Law and Policy Center
1606[3]	Stephanie Montgomery
1606[3]	Steve Frankel
1606[3]	Susan Zingle, Lake County Conservation Alliance
1606[3]	Thomas Robert Hartmann
1606[3]	Vince Bertolini
1608[3]	Al Seiss
1608[3]	Allen Muller, Green Delaware
1608[3]	Amanda Bergson-Shilcock
1608[3]	Angela Ledford, Clean the Air
1608[3]	Ann Wynn
1608[3], 1783, 2889, 2892, 2893, 2894, 2896, 4133, 4134	Barbara Kwetz, Massachusetts Department of Environmental Protection; Robert Golledge, Commissioner, Massachusetts Department of Environmental Protection
1608[3]	Beth L. McGee, Chesapeake Bay Foundation
1608[3]	Bill Hall
1608[3]	Brad Sift
1608[3]	Brian Bradley
1608[3]	Brian Smith
1608[3], 1759	Carol Ward, Dental Amalgan Mercury Syndrom
1608[3]	Cathy Harris
1608[3]	Cercie Urbanski
1608[3]	Christine Cantrell

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1608[3]	Claudia Vanderslide
1608[3]	Coralie Pryde
1608[3]	David Joseph Trickett
1608[3]	David Prescott
1608[3]	Debbie Heaton
1608[3]	Denise Ryan
1608[3]	Dereth Glance, Citizens Campaign for the Environment, NY
1608[3]	Dr. L. Matthew Schwartz
1608[3]	Ellen Silbergeld
1608[3], 1765	Freya Koss, Consumers for Dental Choice
1608[3]	Freyda Black
1608[3]	Gabriel Grabin for Lisa Graves Marcucci, Jefferson Action Group
1608[3]	Germane A. Germeyer
1608[3]	Grace Vodga
1608[3]	Hans Banardson
1608[3]	Harriet Hirslich
1608[3]	Hugh Gorman
1608[3]	Janet Kenepp
1608[3]	Jason K. Barbie, NY Public Interest Research Group
1608[3]	Jay Treat
1608[3]	Jim Black
1608[3]	Joe Connelly
1608[3]	John Le Bourgeois
1608[3]	John Kearney

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1608[3]	John Stanton, National Environmental Trust[2]
1608[3]	John Shennan, Adirondack Council
1608[3]	John Hinck, National Resources Council
1608[3]	John Stanton, National Environmental Trust
1608[3]	Jonathan Lewis, Clean Air Task Force
1608[3]	Julie Bussiere
1608[3]	Kate Territo
1608[3]	Kate Erdei
1608[3]	Kevin Scott
1608, 1778, 3539	Lenny Dupuis and Pamela F. Faggert, Dominion Resources, Inc.
1608[3]	Leslie Smith
1608[3]	Linda Cald
1608[3]	Lisa Zubowicz, PennFuture
1608[3]	Loretta Dunne
1608[3]	Lyman Welch, Mid-Atlantic Environmental Law Center
1608[3]	Mabel Mallard
1608[3]	Magalee Larson Temple
1608[3]	Marsha Low, Clean Air Council
1608[3]	Marvin Lewis
1608[3]	Marvin Lewis
1608[3]	Marvin Thall
1608[3]	Matthew Miller, Maryland Public Interest Research Group
1608[3]	Matthew Miller, Maryland Public Interest Research Group
1608[3]	Mekel Marcy

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1608[3]	Meredith Wood
1608[3]	Michael Ferrantino, Group Against Smog and Pollution
1608[3]	Michelle Wallhagen
1608[3]	Mike Ewall
1608[3]	Mike Rosenberg, Green Party of Philadelphia
1608[3]	Nathan Wilcox, PennEnvironment
1608[3]	Nicholas O. Scull
1608[3]	Peter Lehner, Office of Attorney General of New York
1608[3]	Rich Garella
1608	Robert C. Dalton, Aspect Enterprises
1608[3]	Robin Mann
1608[3]	Rosemary Volpe
1608[3]	Ruth Bolter
1608[3]	Scott Newman
1608[3]	Susan Govreeski, League of Conservation Voters Education Fund
1608[3]	Teresa Mendez-Quigley, Women's Health and Environment Network
1608[3]	Virginia Craciun
1608[3]	W. Robert Campbell, Sierra Club
1608[3]	Walter Stern
1608[3]	William B. Wycoff
1608[3]	William Cook, Citizen Campaign for the Environment
1611[3]	Alice Teich,, Physicians for Social Responsibility
1611[3]	Allison Best
1611[3]	Allison Donnelly

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1611[3]	Beth Barfield, Virginia Independent Power Producers
1611[3]	Bill Delmar
1611[3]	Bill Wood
1611[3]	Braden Craig
1611[3]	Brian Garrett
1611	Brock Nicholson, NC Division of Air Quality
1611[3]	Christine Stefani
1611[3]	Cynthia Walker
1611[3]	Dan Ryan
1611[3]	Dr. Jessica Christie
1611[3]	Dr. John Hammond
1611[3], 2909, 3391	Dr. Luanne Williams, North Carolina Department of Health and Human Resources; B. Keith Overcash, Director, North Carolina Department of Environment and Natural Resources
1611[3]	Gail Rouche, Wake County Association for Retarded Citizens
1611[3]	Hart Pillow
1611[3]	Heather Joacobs, Pamlico-Tar River Foundation
1611[3]	Holly Bankoski
1611[3]	Jeanne Ansley
1611[3]	Jeannene Wiseman
1611[3]	Jill Freeman
1611[3]	Jill Stevens, National Parks Conservation Association
1611[3]	Khristi Tominson
1611[3]	L.C. Coonse

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1611, 4891, 4890, 4892, 4893[3]	Laura LaValle and Michael J. Nasi, Lloyd, Gosselink, Blevins, Rochelle, Baldwin, and Townsend, Texas Lignite Coalition
1611[3]	Mark Zumbach
1611[3]	Mary Frazer
1611[3]	Matt Wasson
1611[3]	Matthew Barton
1611[3]	Michael Stalnaker
1611[3]	Molly Diggens, Sierra Club/North Carolina
1611[3]	Nancy McDermott
1611[3]	Nichole Grice
1611[3]	Nora Gottlieb
1611[3]	Pamela Irwin, Sierra Club/Virginia
1611[3]	Paul Miller
1611[3]	Peter Adler
1611[3]	Peter Walker
1611[3]	Rachel Zajac
1611[3]	Rebecca Robins
1611[3]	Rep. Paul Luebke, NC House of Representatives
1611[3]	Robert Manning, Esq., Hopping Green and Sams
1611[3]	Robin Jenkins, R.N.
1611[3]	Scott Gollwitzer
1611[3]	Senator Ellie Kinnaird, NC Senate
1611[3]	Ti Harmony
1611[3]	Tiffany Urban

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1611[3]	Tim McBrayer
1611[3]	Tom Transue
1611[3]	Wayne Wilson
1611[3]	Wendy Michener
1615	5,092 mass mailings
1618, 2173, 2174, 2175, 2176, 2177, 2178, 2179, 2193, 2194, 2195, 2376, 2377, 3496-3504, 3414, 3415	Al Miham, Forest County Potawatomi Community; Harold Frank, Chairman, Forest County Potawatomi Community; Lawrence Daniels, Natural Resources Director and Therese Hubacher, Air Specialist and Gretchen Watkins, Water Specialists, Forest County Potawatomi Community Tribal Natural Resources/EPA
1619	Andy Knott, Hoosier Environmental Council
1620	Boise D. Jones, Environmental Justice Advocates of Minnesota
1621	Brad Maurer, Ohio Smallmouth Alliance
1622	Carey Hamilton, Save the Dunes Council
1623	Cathy Woolums, MidAmerican Energy Holdings Company
1625, 1772, 1819, 1860, 2929, 4894, 4895, 4896, 5469	Dan Riedinger, John Kinsman, Michael Rossler, Michael Rossler, Quinlin Shea, Michael Rossler, Edison Electric Institute and Charles River Associates (memorandum to Edison Electric Institute)
1626	Danielle Welliever, Evangelical Lutheran Church in America
1627, 3521, 5472	Dennis Leonard and Michael Rodenberg, Detroit Edison Company
1628	Ellen Rendulich, Citizens Against Ruining the Environment
1629	Eric Uram, Sierra Club/ Midwest Office
1629[3]	Eric Uram, Mercury Free Wisconsin
1630	Erin Jordahl Redline, Clean Water Action Alliance

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1631[3]	F. Daniel Cantrell on behalf of Congressman Danny K. Davis
1633	Anonymous
1634	Jean de Smet
1635	John R. Ackerman
1636	David Grafke
1637	Debra Kirchhof-Glazier
1638	Louette Rogers
1639	Winifred and Frederick Wilhelm
1640	Mary M. Sass
1641	Calvin J. Haneline
1642	Diane
1643	Adam A. Krzmarzick
1644	Penelge Perez DeNormandie
1645	Enid S. Winchell
1646	Anonymous
1647	Diana Smith
1648[2]	Rachel Mason
1649	Peggy P. Elliott
1650	Elizabeth Donaldson
1651	Dennis Thomas
1652	William J. Sappenfield
1653	Celine Wozman
1654	Janice Grant
1655[4]	John P. Devine, Jr., Natural Resources Defense Council

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1656	James W. Coursey, Illinois Council of Trout Unlimited
1657	Jean Flemma, Prairie Rivers Network
1658, 2041, 2364	John A. Paul, Ohio Regional Air Pollution Control Agency
1659	John W. Thompson, Clean Air Task Force
1660, 1779	Karen Truskowski, Dental Amalgan Mercury Syndrome
1661	Katherine Duck, Indiana Interfaith Environmental Task Force
1662	Kathleen Schuler, Institute for Agriculture and Trade Policy
1663	Kurt Waltzer, Ohio Environmental Council
1664	Laurel O'Sullivan, Lake Michigan Federation and Delta Institute
1666	Lee H. Walker, New Coalition for Economic and Social Change
1667	Leise Jones, U.S. Public Interest Research Group
1668	Linda Gray Sonner, Presbyterians for Restoring Creation
1669	Marc Looze, Clean Wisconsin
1671	Marcia Wilhite, Association of State and Interstate Water Pollution Control Administrators
1672	Majorie Ettlinger, League of Women Voters and Lake Michigan Interleague Group
1673	Mary Kenkel, Cinergy Corp.
1674	Matt Little, Mercury-Free Minnesota Coalition
1675	Michael T.W. Carey, Ohio Coal Association
1676	Michelle Gottlieb, Physicians for Social Responsibility/ Greater Boston
1677	P. Bruce Hill, Ken American Resources, Inc.
1678	Paul Zugger, Michigan United Conservation Clubs
1679	Peg Lautenschlager, Attorney General, State of Wisconsin
1680	Phillip M. Gonet, Illinois Coal Association

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1681	Rebecca Stanfield, Illinois Public Interest Research Group
1682[3], 1967, 2108, 2109, 3302, 2160	Renee Cipriano, Director, Illinois Environmental Protection Agency; Bill Hoback, Chief, Office of Coal Development and Marketing, Illinois Department of Commerce and Economic Opportunity
1683	Rich Femling, Rose Creek Anglers, Inc.
1684	Robert Shimek, Indigenous Environmental Network
1685	Ryan Canney, Citizen Action Illinois
1686	Sarah Streed, Wisconsin Interfaith Climate and Energy Campaign
1687	Sara Welch, Izaak Walton League of America
1688	Shane Staten, Sierra Club/Missouri Chapter
1689	Verena Owen, Lake County Conservation Alliance
1690	Zoe Lipman, National Wildlife Federation
1692	Hal Quinn, National Mining Association
1693	Vicki Levengood, National Environmental Trust
1694	Anonymous
1695	Norman Birchfiled
1696	Anonymous
1697	Matt Fine Silver
1698	Dan Kien
1699	Anonymous
1700	Anonymous
1701	Anonymous
1702	Anonymous
1703	Anonymous
1704	Anonymous

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1705	Anonymous
1706	Scott Olsen
1707	Anonymous
1708	David Levner
1709	Lynn E. Frederiksen
1710	Anonymous
1711	Rachel Betesh
1713	Anonymous
1714	Melissa D. Bernardin, Clean Water Action
1715[1]	Danielle White
1716	Gabin Barbour and Sarah M. Brown
1717	J.Y.
1718	Mr. and Mrs. Robert Cossins
1719	Janice Gibbons
1720	Lora Chamberline, D.O.
1721	Wilt Stites
1722	Tom Meacham
1723	Lori Chilefone
1724	James J. Norman
1725[1]	Sarah Hunter
1726[1]	John Garrett Baker
1727	Paul Luehrmann
1728	Bethany Knighton
1729	James Balne and Shirely Balne

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1730	Marilina Resasco
1731	Oganes Pahlevanyan
1732	Wendy Hanophy
1733	Richard Schuckman
1734	Elaine Manzeke Eagon and Paul H. Eagon
1735[2]	Sarah Novey
1736	Dr. Lewis Cuthbert, Alliance for a Clean Environment
1737	Catherine E. Anderson
1738	Susie Tanenbaum
1739	Ryan Thomas Morra
1741	Gaylah Balter
1743	Matt Potter
1744	Daniel F. Cebelinski
1746[2]	John Dukovich
1747	Linda S. Sanders
1748	Jeannie Roberts
1749	Brian Jacobs
1750	Marylyn and Stewart Stroup
1751	David B. Olson
1752	Darsi McCarthy
1753	Anonymous
1755[2]	Ellen K. Silbergeld, Professor of Environmental Health Sciences and Epidemiology, John Hopkins University
1755[3]	Michael McCally, Physicians for Social Responsibility

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1757	Rev. Arthur Waskow, Shalom Center
1758	Dr. Bert Zauderer, Coal Tech Corporation
1761	Catherine Bowes, National Wildlife Federation
1762	Dr. Lynn Shanks, Maple Creek Mining, Inc.
1763, 2886, 2887, 2888, 2890	Dawn R. Gallagher, NESCAUM; Praveen Amar, NESCAUM
1764	Frank O'Donnell, Clean Air Trust
1766	Gary Anderson, ARIPPA
1768, 3530	Jeffrey Marks and Dave Harvey, National Association of Manufacturers
1769	Jeffrey W. Stehy, University of Maryland Department of Meteorology
1770	Jerome Balter, Public Interest Law Center of Philadelphia
1771	John Hinck, Natural Resources Council of Maine
1773, 3441, 3442	Joseph Otis Minott, Clean Air Council
1774	Joy Bergey, Center for the Celebration of Creation
1776	Karen Hadden, Sustainable Energy and Economic Development Coalition and Public Citizen
1777, 2764	Kyle Kinner, Physicians for Social Responsibility
1779	Michael Gross, Coalition on the Environment and Jewish Life
1780	Nancy Parks, Sierra Club, Pennsylvania
1781, 2924, 2925, 3567	Nicholas DiPasquale, Commonwealth of Pennsylvania, Pennsylvania Department of Environmental Protection
1782	Omar Taylor, Northeast Environmental Justice Network
1785	Sharon Finlayson, New Jersey Environmental Federation
1786	Susan Gobreski, League of Conservation Voters Education Fund

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1788	Wisssahickon Charter School
1789	Ed Knorr, Green Action Alliance
1790, 1857, 1784, 3516	Scott Segal and Frank Maisano, Electric Reliability Coordinating Council
1791	Gilliam Ream, Maryland Public Interest Research Group
1792	Jeffrey Solow
1793	Mayoli Larson
1794	Navis Bermudez, Sierra Club
1795	Charles T. Mcllhinney, Jr., Pennsylvania House of Representatives
1796[3]	Amy Schaich
1796[3]	Arthur Stamoulis
1796[3]	Brandy Mangum
1796[3]	Brian Garrett
1796[3]	Christine Wunsche
1796[3]	Christine Miller
1796[3]	David Armstrong
1796[3]	David and Marsha Low
1796[3]	Dr. Jessica Joyce Christie
1796[3]	G.A Germeyer
1796[3]	Henry Jonas Magaziner
1796[3]	Janet Nyce
1796[3]	Joan Candalino
1796[3]	Lisa Mosca
1796[3]	Loretta Dunne

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1796[3]	Marc Guerra, M.D.
1796[3]	Melissa Gee
1796[3]	Michelle Walhagen
1796[3]	Mollie Brown
1796[3]	P.J. Puryear
1796[3]	Paul Nettesheim
1796[3]	Paul Murray
1796[3]	Sue Althouse
1796[3]	Sylvia Buchlioz
1797	Alice Garland on behalf of John Edwards, U.S. Senate
1799	Allison Martin, South Carolina Coastal Conservation League
1800	Amy Carson, Moms Against Mercury
1802	Charles R. Wakild, Progress Energy Service Company
1803, 1854	David Duncan
1804, 3454, 3455, 3563, 5056, 5500, 5591	David Foerter, Institute of Clean Air Companies
1805	David Knight, Sierra Club
1806	Elizabeth Ouzts, North Carolina Public Interest Research Group
1807, 4962	Felice Stadler, National Wildlife Federation
1809	Harvard Ayers, Appalachian Voices
1810	Hope Taylor-Guevara, Clean Water for North Carolina
1811	Jeff Gleason, Southern Environmental Law Center
1812	Dr. John C. Pittman, North Carolina Integrative Medical Society
1813	Katherine Shea, Physicians for Social Responsibility

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1814	Kris W. Knudsen, Duke Energy Corporation
1815	Lewis Patrie, Physicians for Social Responsibility, Western NC
1816	Marmie Clark, Elders for Peace
1817	Martha Keating, Clean Air Task Force
1818, 2945	Michael O. McKown, Murray Energy Corporation
1820	Michael Shore
1821	Mike Evans, North Carolina Wildlife Federation
1822	Richard Harkrader, North Carolina Sustainable Energy Association
1823	Tancred Miller, Sierra Club, North Carolina
1824	Valerie True, Southern Alliance for Clean Energy
1825	Louise Romanow, League of Women Voters of Wake County
1826, 5484-5487, 5489	Danny Herrin and C.M. Hobson, Southern Company
1827	Mary Alsentzer and Heather Jacobs, Pamlico-Tar River Foundation
1828	Pediatric Health Professionals
1829	Sarah Heath Olesiuk
1834	David W. Knuth, Marshall County Chamber of Commerce
1835	Tracy V. Drake, Chief Executive Officer, Columbian County Port Authority
1836	Lucille P. Duca
1837	5 mass unknown mailings
1838	Rem and Louise Edwards
1839	Sheralyn M. Heyse, R.N.
1840	Patricia Ann Young
1841	Dr. Jennifer L. Howse, President, March of Dimes

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Docket ID No. OAR-2002-0056	Commenter
1842	The McIlvaine Company
1843	Daria Barbour
1844	Lou Ann R. Danforth
1848[3]	Amanda Champany, Colorado People's Environment for an Economic Network
1848[3]	Amy Livingston
1848[3]	Amy Prater, Washington Park United Church of Christ
1848[3]	Andrew Kear
1848[3]	Bruce Glenn, Eco-Justice Ministries
1848[3]	Carol Boigon, City Councilwoman for Denver
1848[3]	Charles Wanner, San Juan Citizens Alliance of Durango Colorado
1848[3]	Clarence Baer, First Plymouth Congregational Church
1848[3]	Cody Hamilton
1848[3]	Dan Halleman
1848[3]	David Grossman
1848[3]	David Barber, Citizens for Clean Air and Water in Pueblo and Southern Colorado
1848[3]	Dr. David B. King
1848[3]	Dr. Ken Gerdes
1848[3]	Elizabeth O'Donnell
1848[3]	Emma Young
1848[3]	Eric Phillips-Nania
1848[3]	James Todd
1848[3]	Jeremy Neufeld
1848[3]	John Roper

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Docket ID No. OAR-2002-0056	Commenter
1848[3]	Josh Blum
1848[3]	Joyce Johnson
1848[3]	Judy Linski
1848[3]	Justin Dawe, Environment Colorado
1848[3]	Ken Regelson
1848[3]	Kristin Casper, Greenpeace Clean Energy Now
1848[3]	Leslie Glustrum
1848[3]	Lin Berrett
1848[3]	Lynn Judson
1848[3]	Marilyn Starns
1848[3], 1848[3], 2094, 2660	Michael Fowler, Permit Section, New Mexico Environment Department; Sandra Ely, Air Quality Section, New Mexico Environment Department; Dr. Ronald E. Voorhees, New Mexico Department of Health; Ron Curry, Cabinet Secretary, New Mexico Environmental Department and Patricia Montoya, Cabinet Secretary, Department of Health
1848[3]	Noah Zakim
1848[3]	Rafaele Schiffman
1848[3]	Rebecca Dickson
1848[3]	Rich Rebman, Renegade Research
1848[3]	Sarah Milligan
1848[3]	Sean Schumer
1848[3]	Sonya Guram
1848[3]	Steven Krichbaum
1848[3]	Tom Dickson-Hunt
1848[3]	Unny Nambudiripad, Western Clean Energy Campaign

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1848[3]	Wayne Massi
1851	Andy Schultheiss, League of Conservation Voters Education Fund
1852	Carrie Kowalski, KFX Inc.
1853	Cindy Copeland
1856	Elizabeth Andrews, National Environmental Trust
1858	John Rosapepe, Sierra Club, Rocky Mountain Chapter
1859	Lee Eberley, XCEL Energy
1861	Pam Milmoe, Boulder County Public Health
1862	Rich Moore, Grand Canyon Trust
1864	Alicia Delgado
1865	Andrew Van Lue
1866	Anonymous
1867	Danielle Koepke
1868	Ellen Salvador
1869	Judy Raizen
1870	Michael Maer
1871	Naccome Chaunto Garlich
1872	Paul D. Garcia
1873	Raquel Holguin
1874	Ryan Yoder
1875	Windy Elizabeth Cook
1876	Zoila Lora Saputo
1877	Anonymous
1878	Mary T. Bowen

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Docket ID No. OAR-2002-0056	Commenter
1879	Victoria S. Awarey
1880	Vise and Laura Vise
1881	Kurt Karbusicky
1882	Glynis Kinnan
1883	Karen Rahn
1884	Janet C. DiNapoli
1885	Lorrie Streifel
1887	Barbara J. Hamill
1888	Lori Segall
1889	Robert Farley, Princeton-Mercer County Chamber of Commerce
1890	Ron Shaffer
1891	Cheryl Pomeroy
1892	Vickie L. Jones
1893	Janet I. Green
1894[2]	Natalie Faes
1895	Albert L. Walker
1896	Daniel S. Moroney
1897	Shelly Moran
1898	Laurie A. Fitch
1899	James Conroy
1900	Emmett S. Pugh III, Mayor, City of Beckley
1901	David A. Schultz
1902	James. H. Douglass, Governor, State of Vermont
1903	Maria Keirnan

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Docket ID No. OAR-2002-0056	Commenter
1904	Crystal Michaliszyn
1905	Anonymous
1906	Anonymous
1907	Deborah Scott
1908	Jeanne E. O'Neill
1909	Edward Hayden
1910	Alison Wiley
1913	Anonymous
1914	Tom Ward
1915	Darwin Spaysky
1916	Sue E. Anderson
1917	Earlene Webster
1918	Anonymous
1919	James R. Sutton
1920	Mary Kay and Rick Wilson
1921	Hank Epstein
1922	Dolores Petry
1923	John D. Lloyd, M.D.
1924	Paul K. Holmes
1925	Dr. Pamela Hannaman-Pittman
1926	Julia Glenn
1927	Eileen Weinsteiger
1928	Ruby Hruby
1929	James W. Buchanan

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Docket ID No. OAR-2002-0056	Commenter
1930	Kem Moser
1931	Jocelyn Muggli
1932	Karl and Kathy Richardson
1933	Tammy Mercer
1934	Michael Pease
1935	Sharon Outler
1936	Jane Scudder
1937	Dianne E. Adams
1938	Jasper J. Medici
1939	Cary Terral
1940	Deborah Pardi
1941	Peter Carminati
1942	Thomas Pullano, M.D.
1943	Kathleen Stried Noe
1946	Geoff Schaefer
1950	Jenny Pike
1951	Nancy Rissler
1952	John K. Alderman, President, Material Automation Systems and Service, Inc.
1955	Robert A. Wyman et al., Latham and Watkins
1956	Mary Gorman
1957	Anonymous
1958	Anonymous
1959	Amy Mattix

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Docket ID No. OAR-2002-0056	Commenter
1960	Robert Plumley
1961, 3470	Carl E. Benne, Chairman, Crow Tribe of Indians, Crow Tribe Executive Branch
1962	Anonymous
1963	Cindy
1964	David G. Hill
1965	Heather Doyle
1966	Chris Keenan
1968	Regis McCann
1969	Terry Graumann, Manager, Otter Tail Power Company
1970	Frank N. Egerton
1971	Anonymous
1972	Anonymous
1973	Kristi Espiinoza
1974	Anonymous
1975	Ed Leary
1976-1984	EPA Telephone Hotline Comments covering 19 Jan 2004 through week of 22 March 2004
1986	Diane St. Germain
1987	Terry Aikin
1988	Al and Marti Marino
1989	Karl B. Bucholz and Karen H. Robinson
1990	Mark Jacobson and Phyllis Stuart-Jacobson
1991	Patricia P. Willis and Thomas M. Willis, Jr., Adirondack Mountain Club

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Docket ID No. OAR-2002-0056	Commenter
1992	Cheryl Pomeroy
1993	Jean M. Geissler
1994	Jennifer Brook-Kothlow
1995	A. Carmen
1996	St John's Church senior class
1997	Marcia R. Kaminski
1998	Alfred and Mary Jane Hasemeier
1999	Anonymous
2000	Janice Owens
2001	Peter Kozlowski
2002	Dennis Miller
2003	Marni J. Good
2004	Janet Burkhart
2005	Joanne Holbrook
2006	Richard Schuckman
2007	Dr. A-Lea Salis Louis
2008	Russell Hill, Vice President, Boral Material Technologies Inc.
2009	Mark Johnson
2010, 2013	Frank Ettawageshik, Odawa Tribal Chairman
2011	Neil F. Woodworth, Counsel, Adirondack Mountain Club
2012	Anonymous
2014	Georgina M. Lampman, President, Water Quality Section, American Fisheries Society
2015	Anonymous

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Docket ID No. OAR-2002-0056	Commenter
2016	Anonymous
2017	Laurie Puscas
2018	Luanne K. Williams
2019	Nate Lengacher
2020	Judy Sewell, Henderson Area Chamber of Commerce
2021	Anonymous
2022	Anonymous
2023	R.T. Rybak, Mayor of Minneapolis
2024, 2025	Lynn Hardwick
2026	DuWayne A. Wenger
2027	John W. Barnett
2028	Jennifer K. Bunting
2029	Nancy Wiegand
2030	Judy Archibald
2031, 2262	Dereth Glance and Adrienne Esposito, Citizens Campaign for the Environment
2032	Anonymous
2033	Austin Investors
2034	Tami Burdo
2035	Eileen Kramer
2036	Anthony and Patricia Busalacchi
2037	Rita M. Jarman
2038, 2367, 2854, 2858, 4916-4929, 4983-4985	David Sleeper, Hubbard Brook Research Foundation and 35 mercury scientists

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Docket ID No. OAR-2002-0056	Commenter
2040	Joseph Siperstein, President, Ohio Lumex Company
2042	Rodger a. Kershner, Howard and Howard Attorneys
2043	Kirby Tyndall, Ph.D.
2045	Kent Newman
2046, 2432, 2433, 2502, 2521, 5282, 5332	Anne G. Berwick, Associate Director, The Clean Energy Group
2047	Anonymous
2048	Anonymous
2049	Los Alamos National Laboratory
2050	Anonymous
2051	Barbara J. Crouch
2052	Carol Braswell
2053	Jeannie Bridges
2054	Dennis R. James, Fuel Quality Administrator, North American Coal Corporation
2055	Anonymous
2056	Craig Kullman
2057	American Academy of Pediatrics, American Public Health Association, Alliance for Healthy Homes
2058	Joe Miner
2062	Andrew Eisenberg, MD, Chair, Texas Medical Association
2063, 5429-5440	Jean B., ADA-Environmental Systems, and Sheila Glesmann, Emission Strategies, Inc.
2064, 2213, 2359, 2905	Al Shea, Administrator, Air And Waste Division, Wisconsin Department of Natural Resources; Scott Hassett, Secretary, Wisconsin Department of Natural Resources

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Docket ID No. OAR-2002-0056	Commenter
2065	John M. Wylie
2066	Norbert Dee, Director, Environment and Safety, National Petrochemical and Refiners Association (NPRA)
2067	Mr. Simon, Manager, State Government Relations, Missouri River Energy Services
2068, 2069-2070, 5477	Frederick D. Palmer and Roger B. Walcott, Jr., Peabody Energy
2071	Thomas Dernoga, Chair, Metropolitan Washington Council of Governments
2072	Karen Banks
2074	Anonymous
2075, 2266	John Stroud, President, North East Texas Economic Developers Roundtable
2076	Anonymous
2077	Anonymous
2078	Stanton W. Rogers
2079	Energy and Environmental Research Center
2080	Anonymous
2081	Charles Revill
2082	Gary and Nancy Haygood
2083	Gary L. Spicer
2084	Theodore Keebaugh
2085	Stephen E. Woock, Weyerhauser
2086	Anonymous
2087	Leon F. Szeptycki, Trout Unlimited Eastern Conservation Director
2088	Del McCabe

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Docket ID No. OAR-2002-0056	Commenter
2089	Debbie Lennie
2090, 2142	Brian Houseal, The Adirondack Council
2091, 2331	D. L. Berry, Regulatory Affairs Expertise Center, Dow Chemical Company
2092	John Denman
2093	Jerry Wood
2095	Anonymous
2096	Anonymous
2097	Cliff Germain
2098	Arthur B. Scharlach
2099	Anonymous
2100	Anonymous
2101, 2103	Tekran Inc.
2102	Hughes Stanley
2104	Raylene Patterson Conner
2105, 2220, 2231	Kevin S. Barnett, Senior Consultant, Alcoa Corporate Center
2106	Sue Steinmo
2107	Joel Swadesh
2110	Cathy Green
2111	Brian T. Traux
2112	Carl E. Edlund, EPA Region 6
2113	Cynthia Durlin
2114	Stephanie Green, Texas Public Interest Research Group
2115	G.E. West, Chairman, Committee of Energy Resources, Texas House of Representatives

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Docket ID No. OAR-2002-0056	Commenter
2116	Gifford Miller and Christine Quinn, New York City Council Committees on Environmental Protection, Health, and Waterfronts
2117	Michael K. Taylor, Rea and Associates
2118	Donald Moore, Sr., Tribal Chairman, Bad River Band of Lake Superior Chippewa
2119	Dee W. Hart, Tatum District School Superintendent
2120	Ronald F. Hammerschmidt, Director, Kansas Department of Health and Environment
2121	Mass campaign, Unitarian Society of North Hampton and Florence
2122	Joyce Watts
2123	Kenneth H. Busz, Huntington Regional Chamber of Commerce
2125	Mary L. Jelks, MD
2126	Stan Pitts
2127	Frank Carl
2128	Tiffany Cesto, et al.
2129	John Hubert
2130	Douglas Pintar
2131	C.J. Guerin-Fuoco
2132	Joy Drohan
2133	Ben Hueftle
2134	Grace E. Grant
2135	Robert D. Herron, James R. Griffith, and Terry L. Wagner, Carroll County Board of Commissioners
2136	E. Howard Youmans
2137	Gail G. Kincaide, Executive Director, Association of Women's Health, Obstetric and Neonatal Nurses

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Docket ID No. OAR-2002-0056	Commenter
2138	Pat Parsons
2139	Sarah Swinerton
2140	Jan Charvat
2141	Edith Chase
2143	Fred E. Werner
2144	Donald S. and Mary C. Robinson
2145	Jason Flores
2146	Karen J. Miller
2147	Barbara Benson
2148	Caren M. Kanin
2149	Carol Wyocki, President, ECHO
2150	Mary Qincian
2151	Em'rym Artvnian
2152	Robert C. Ashley
2153	Alex Bowers
2154	Jan Waterman
2155	Susan and Robert Wildermuth
2156	Ruth E. Stiver
2157	Robert and Janice Carrico
2158	Mary Jane and Alan Williams and family
2159	Shirley and Rong-sheng Jin
2161	James M. Parker, Manager, Environmental Engineering, PPL Montana, LLC Colstrip Steam Electric Station

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2162, 2184	Bill E. Ramsey, Executive Director, Association of Independent Power Producers in the Anthracite and Bituminous Regions of Pennsylvania (ARIPPA)
2163	Clifton H. Brown, Jr., President, ADA Technologies, Inc.
2164	Anonymous
2165	Anonymous
2166	Erica
2167, 2168	Patrick Sheedy
2169	Robert E. Busch, President and Chief Operating Officer, PSEG Services Corporation
2170, 2441	Cecil E. Roberts, President, United Mine Workers of America
2171	Anonymous
2172	American Municipal Power-Ohio
2180	Bradley H. Spooner, Environmental Sciences, Municipal Electric Authority of Georgia (MEGAPOWER)
2181	Neal Pospisil, Director, Safety, Health, and Environment, Calpine Corporation
2182, 2183	Eric Fingerhut, U.S. Senate
2185	65 mass mailings
2186-2192	Robert Ferguson, Executive Director, Center for Science and Public Policy
2195	Lee A. Dew, Ph.D.
2196	Martha Bergsten
2197	Jan Gares
2198	Ali Mirzakhalili, Administrator, Division of Air and Waste Management, Delaware
2199	Jim DiPeso, Policy Director, REP America

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2200	Ernest Charles Carwey
2201	Brenda Rothstein
2202	Mary Johnston
2203	Alana Aronin
2204	Judge Danny Pat Crooks, Titus County, Texas
2205	Maureen K. Headington, President, Stand Up/Save Lives Campaign
2206	Karen Ritter, Senior Regulatory Analyst, American Petroleum Institute
2207	Diana Kennedy and Pat Carr, Mount Pleasant and Titus County Chamber of Commerce
2208	C.J. Stood
2209, 2412, 2413	Stan Scott, et al.
2210	John Nils Hanson, Chairman, President, and CEO, Joy Global, Inc.
2211	Claudia A. Clifford, Executive Director, Montana Nurses Association
2212	Roger D. Hailey, Henderson County School Superintendent
2214	Tony Wooster
2215	Joyce Raines
2216	Sandra G. Miller
2217	Rachael Elwes
2218	Sue Henderson, General Manager, Henderson Economic Development Corporation
2219	Laurel O'Sullivan, Lake Michigan Federation and Abigal Corso, Delta Institute
2221	Mike Fields, Titus County Commissioner
2222	Dawn Falleur, Green Environmental Coalition
2223	Hudson Old

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2224	Lynne H. Church, President, Electric Power Supply Association
2224, 2356	Todd Staples, Texas State Senate
2225	Laurie Maher
2226	Anne Sellers
2227	Bonnie New, Health Professionals for Clean Air
2228	Dennis Bonnen, Texas House of Representatives
2229	Dr. Jonathan S. and Elizabeth B. Griffiths
2230	Roy Sanders and Dolores Sanders
2232	Judge Sandra Hodges, Rusk County
2233	Bruce Hoeft
2234	Ben Glacken
2235	Joel P. Palin
2236	Patrick Huber
2237	Illegible
2238	Victor Marrero
2239	Jonathan Todd
2240	Francesca C. Howe
2241	Dan Hall, NH Trout Unlimited Council
2242	Fred Sampson, President, West Virginia Environmental Council
2243	James B. Thompson, Senior Vice President, Indeck Energy Services
2244	Michel R. Benoit, Executive Director, Cement Kiln Recycling Coalition
2245	Lanier and Sandra Brumback
2246[1, 3]	J.C. Wynn

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2247, 4311[2], 2378	Sheryl Corrigan, Commissioner, Minnesota Pollution Control Agency; Ann Jackson, Minnesota Pollution Control Agency
2248, 2249, 2250	William L. Kovacs, Vice President, Environment, Technology and Regulatory Affairs, U.S. Chamber of Commerce
2249, 2268	David Doniger, Policy Director, NRDC Climate Center
2251, 2252, 2253, 2254, 2255, 2256	Stephen L. Miller, President and Chief Executive Officer, Center for Energy and Economic Development
2257	Anonymous
2258	Anonymous
2259	James Reynolds, President, CR Clean Air Technologies
2260	Mark W. Schwirtz, Apache Station
2261	Joseph Bologna, North Branch Energy, Inc.
2263	Cedric Robinson
2264, 1848, 1855	Peter Keppler, Chairman, Stuart Sanderson, and Dianne Orf, Colorado Mining Association
2265	Caribou Commons Society et al.
2267	Andrew L. Kolesar, Thompson Hine (for City of Hamilton)
2269, 2270, 2271	John Harja, Executive Director, Utah Resource Development Coordinating Committee
2272	Anonymous
2273	Robert Dalton
2274	Chris Tyler
2275	Judy Archibald
2276	Anonymous
2277	Roy W. Wood, Eastman Kodak Company

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2278	Anonymous
2281	The Wiggins family
2282	M.A. Fischette
2283	M.T. Brace
2284	Leah Graygor
2285	Mary L. Kuenn
2286	Scott Wilde
2287	Robert Holbrook
2288	Dorrance and Lydia Halverson
2289	Timothy A. O'Shea
2290	Carol Schulz
2291	Michael Sticht and Donna Wyszomierski
2292	Beverly J. O'Roake
2293	Rebecca Satryan
2294	Genevieve F. Healy
2295	Richard Parker
2296	Mary Ann Baumgart, Minnesota Valley Testing Laboratories
2297	Matthew Tanner
2298	Kay Brenholt
2299	John W. Parsons, Jr.
2300	Basil R. Northam
2301	Laurie B. Egre
2302	Kate Sherwood and Pieter van Niekerk
2303, 2369	150 mass mailings

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2304	D.N. Montgomery
2305	Lorna Kircher
2306	Louise L. Gregg
2307	Janet Morton
2308	Ellen Eisele
2309	Keith Williams
2310	Zeke Martinez
2311	Jeff Jones
2312	Robert Adams
2313	Phyllis McCormick and family
2314	Jerry Johnson
2315	James M. Dooley
2316	Peter Shank
2317	Carol White
2318	Crystal Lew
2319	Jessica Osgood
2320	John Barrett
2321	Ann Marie Davis
2322	David Fulton
2323	Donald R. Meyers et al., Eastern Ohio Development Alliance
2324	Andy Patterson, Chairman, Southern Alleghenies Conservancy
2325	Ragnhild Holmquist
2326	Sarah Merrill
2327	Blondell Reynolds Brown, Philadelphia City Council

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2328	Robert G. McIntosh
2329	Thomas D. Korns, President, Wells Creek Watershed Association
2330	Nancy C. Wrona, Director, Air Quality Division, Arizona Department of Environmental Quality
2331, 2091	Don Berry, The Dow Chemical Company
2332	Dennis Norton, Manager, Environmental Services, Portland General Electric Company
2333	William Rossbach, Chair, Missoula City-County Air Pollution Control Board
2334, 3345, 3346	Paul N. Cicio, Executive Director, Industrial Energy Consumers of America
2335	64 Members, Minnesota House of Representatives
2336	Carol Siewert
2337	Anonymous
2338, 2339	Nelson Klein
2340	20/20 Vision et al.
2341	American Lung Association et al.
2343	Marion and Joyce Cavanaugh
2344	Anonymous
2345	Betty Ponder
2346	Janet E. Bailey, Executive Director, Development Authority of Mercer County
2347	Lee A. Dew
2348	58 mass mailings
2349	Marcus H. Higginbotham
2350	Sid Stroud

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2351	Brett Derveloy
2352	Ann Louis Heckert
2353	Brent L. Warner
2354	Thomas M. Menino, Mayor of Boston
2355	John Auerbach, Executive Director, Public Health Commission, Boston, Massachusetts
2356	Todd Staples, Texas State Senate
2357	Dan Olson, President, Western States Air Resources Council
2358	Tish Mammeli
2360	Alice C. Butler
2361	Dannie Joe Flandry
2362	Michael R. Helfrich, President, Codorus Creek Improvement Partnership
2363	April Ingle, Executive Director, Georgia River Network
2365	Larry LaMaack, Executive Director, Wyoming Municipal Power Agency
2366	Brenda Garmon
2368	Cherly K. Middleton
2370	Sharon G. Mabbott
2371	Michael J. Carlson
2372	Gordon C. Crighton
2373	Outdoor Gardeners
2373	Ruth Almond, et al.
2374	J. Cagozzelli
2375 5365	Bryant Danner, Executive Vice President, Edison International

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2380 2559	Pearl Capoeman-Baller, Chairperson, National Tribal Environmental Council
2381	Jason E. Pacifico
2382	Kevin Ronkko
2383	Sue Flynn
2384	Jeanete Liu
2385	Bartholomenv S. Tapoly
2386	Kourtney Salzman
2387	Victor Mercycles
2388	Julian Bauman
2389	Kathryn Denny, Unitarian Society of Northamption and Florence
2389	Kathryn Denny
2390	Jane J. Henzy
2391	BP
2392	Lucy Sullivan
2393	Scott K. Gray
2394	Helen and Thomas Powers
2395	Scott Taylor
2396	Mrs. Norman Baglini
2397	Shabnaum Singh
2398	Ann Jones
2399	Rod Kinard
2400	Flora Jones
2401	Fred Lennox

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2402	Kristal Fredriksen
2403	Tim G. Bywer
2404	Jeanne Taylor
2405	Helena W. Melone
2406	Aspam Pearson
2407	Katelyn Anne Dolan
2408	Mrs. D. Meritt
2409	Ann Antonucci
2410	Kimberly Soaper
2411	Madeline Sone
2412, 2413	845 mass mailings
2414	David L. Gard, Michigan Environmental Council
2415	Jim Bahl, President, Minnesota Conservation Federation
2415	Jim Bahl, President, Minnesota Conservation Federation
2416	Carol Benham
2417	Joe Simecek
2418, 2455	Heather Leslie
2419	Fritz Beckworth
2420, 2543, 2544	Steven Brown, Vice President, Environmental Council of the States
2421	Anonymous
2422, 2876, 2434, 2435, 2436, 2874, 2877, 4254, 4255, 4256, 5457, 5459, 5510	Harold P. Quinn, Senior Vice President and General Counsel, and A. Todd Johnston, Director, National Mining Association

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2423	Hunter Ritter
2424	Nora Freeman
2425	Mae R. Petrie
2426	Wayne Stroessner, Wisconsin Interfaith Climate Change Campaign
2427	Betty Hedges, President, Rockland County Conservation Association
2428	Ray Allen, Texas House of Representatives
2429	Mark J. Sedlacek, Director of Environmental Services, Los Angles Department of Water and Sewer
2430	Chuck Layman, Central States Air Resources Agencies Association
2431	Paul Oakley, Executive Director, Coalition for Affordable and Reliable Energy
2437	Conclan Kilernman
2438	T. Materazzi
2439[2]	42 mass mailings
2440	Kathryn Rolfes
2442	Russell W. Owens
2443	Shelley Eckert
2444	Mary Sheppard
2445	Charlene Hoag
2446	Name illegible
2447	Maureen Larsen
2449	James French
2450	Joseph Orenstein
2451	Richard Dunn
2452	Bruce D. Alexander, Strategy Manager, Exelon Corporation

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2453	Joseph Bello
2456, 2457, 2516, 2517	Sally R. Weiss, M.D.
2458[1]	Anonymous
2459	Andrea Pazandak
2460	Walter Whitehead
2461	Kathy S. Brown
2462	Gail McGraw
2463	Margaret Easter
2464	Anonymous
2465	Jim Koop
2466	Joanne M. MCormack
2467	Kathy Morley
2468	Sharon M. Stoltzfus
2469	Robert and Dyan Ellebracht
2470	Christina Hayakawa
2471	Dr. Justin J. Kelly
2472	Maryann Letiecq
2473	June Ford
2474	Tom Todia
2476	Anne C. Fishel
2477	Larry J. Krutho
2478	Marjorie S. Price
2479	Jessica Grant

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2480	Karen Green Stone
2481	Kari L. Dudley
2482	Karen Salzman
2483, 4189	William W. Phillips, Aroostook Band of Micmacs
2484	Anonymous
2485, 2486	P.S. Analytical, Inc.
2487	Anonymous
2488	Dana Pye
2489	Amanda Hensley
2490	Susan Marlow
2491	Stephen
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2493	Carolyn Lunsford
2494	Janice Williams
2495	Peggy Loddengaard
2496	Jackie Carlson
2497	Tammy Dohr
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2499	Kerchstin Wipperfurth
2500	Carol Anne Valdez
2501	Karen R. Mason
2503	Rita Childo
2504	Robert D. Teetz, Director, Environmental Engineering and Compliance, Keyspan Corporation

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2506	D. Knott
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2508	Lorraine McKnerney
2509	Effie P. Stewart
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2511	Sondra Morrison
2512	Kathy MacLean
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2515	Andrea Stabler
2516	Heather Leslie
2517	Dr. Sally R. Weiss
2518	Anonymous
2519, 3536, 5494	C.V. Mathai, Manager for Environmental Policy, Arizona Public Service Company
2520	Margaret Spittler
2522	Ryan Grant
2523	Keith J. Dittrich, President, American Corn Growers Association
2525	T.G. Tyler
2526	The Marshall household
2527	Hyn Geldes
2528	Joan Shapiro
2529	Brian Pockat

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2532	Anonymous
2533	Anonymous
2534	Anonymous
2535, 2379	Robert M. Boettcher, Subbituminous Energy Coalition
2536	Monique Allen
2537	Robert E. Rutkowski
2538	Jessica Grabowski
2539	Kent Bailey
2540, 3264	John Derrickson, President, Friends of Upper Mississippi Fisheries Services
2541, 2542	Craig Scherenem
2546	Chris Conkey
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2548	Carol Roca
2549	Mary Brenneman
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2552	Lenard Fitzgerald
2553	Jeremy Anderson
2554	Karen A. Patten, Vasilios Keramidas, and Anastasia Kermidas
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2558	Mackie Wesley
2560	George G. Thullesen, District Electric Company (Empire)
2561	Carol Wilson
2562	James Rapp
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2564	Gordon Wenger
2569	Wade Diel
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2571	Anonymous
2575	Waterkeeper Alliance
2576	Anonymous
2577	Alabama Department of Environmental Management
2578, 2279, 2280, 2581, 2582, 2583, 2584, 2585, 2586, 2587, 2588, 2589, 2590, 2591, 2592, 2593, 2594, 2595, 4886, 4887, 4888, 5450-5450	Richard Carlton and Leonard Levin, EPRI
2596	Erin Reilly
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2610	Jill Thompson
2611	Ronald R. Shelton
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2616	Amanda Wong
2617	Left Corner Green Team
2618	Glenn S. Shealy
2619	C.D. Piner
2620	Michael A. Donlon, MD
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2623	Don Cooke

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2627	James R. Hughes, MD
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2631	Josh Nunya
2632	Brian Fitzpatrick
2633	Kevin Paulison
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2652	Ivor R. Moskowitz
2653	Lee Patten
2656	Kate Lester
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2659	Randall G. German
2661	Associated Electric Cooperative
2662	Valerie Taylor
2663	Mary L. Zaron
2664	Mary Helen Korlich
2665	Jerry Balash
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2668	Noel M. Smith
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2678	Michael J. Mayo
2679	Victoria Crompton
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2681	Jamie Frailey
2682	Arthur Bailey
2683	Julie Martha
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2685	Ronald Goldberg
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2689	Donald R. Burgess, American Academy of Pediatrics
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2694	Ben Johnson, Makah Tribal Council Chairman
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2712	Anonymous
2713	Christopher Gavigan
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2716	Meem Lewandoski
2717	Kathy G. Lesiuk
2718, 5404	Cinergy Corporation
2719	Jerri Higgins
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2725	Jim Sims, Western Business Roundtable
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2731	Anonymous
2732	Deborah Swarts
2733	Anonymous
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2735	Anonymous
2736	Steve
2737	Carlos Vazquez
2738	Rosemary Volpe
2739	Harry Miller, MD
2740	Corrine Cody
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2750	Connie Conklin
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2753	Lindsay Lafford, MD
2754	Sheila Kryston
2755[2]	Michael J. Myers, Assistant Attorney General, New York Environmental Protection Bureau
2756	Laura Kay Collins
2757	Elinor Brady
2758	Max and Mary Herink
2759	Teresa G. Lyons
2760	Dr. Ouida W. Meier
2761	Barbara Sachau
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2763	Tom Collina
2766[1]	Rebecca Zimmerman
2767	Phillip Clapp, President, National Environmental Trust Joint Comments
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2777	Margaret E. Emerson
2778	Janet A. Holden
2779	Leslie Hodes
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2782	Barry and Janis Sandt
2783	Dolores Jordan
2784	Geralyn Leannah
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2786[1]	Harold Slosson
2787	James Burgen
2788	Lorne K. Garrettson, MD
2789	Gordon B. Glade, MD
2790	Mary L. Brenneman
2791	Mary L. Wright
2792[2]	Mary McQueen
2793	Gunnel Fernikoff
2794	R. Siekkinen
2795	Edward M. Brown, MD
2796	Michael Germain, MD
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2803	Martha Johnson Gilburg
2804	Mary Low
2805	Sylvia Dawkins
2806	Tina
2807	Vicki Neal
2808	Winchester Dermody and Chrisoula Kiriazis, MD
2809	Caroline Ailanthus
2810	David Addison
2811	Deborah Leiner, MD
2812	Laura M. Holbrook
2813	Michael Lippa
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2815	Christina Studt
2816	Gary L. Hickey, Dynegy Inc.
2817	M. Jane Brady, Attorney General, State of Delaware
2818	George Ellis, Pennsylvania Coal Association

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2821	Candace Pratt
2822	M. Brant
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2824	Mark Venable
2825	Anonymous
2826	Association of Illinois Electric Cooperatives
2827, 2828	Robert J. Barkanic, PPL Services
2829	Anonymous
2830, 5482	N.D. Lignite Energy Council
2831	Anonymous
2832	Joseph D. Leary
2833	Jeffrey Marks, National Association of Manufacturers
2834	John T. Graves, Environmental Manager, Minnkota Power
2835	William Neal, Large Public Power Council
2836, 2840	James Jeffords et al., U.S. Senate
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2842, 3341	Gerard B. Mack, Project Manager, Estill County Energy Partners, LLC)
2843	Sand Sage Power
2844, 3541	Richard T. Bye, Texas Genco LP
2845	Unions for Jobs and the Environment
2846	Robert J. Vann II
2847	W. Earl Watkins, Jr. Sunflower Electric Power Company
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2849	John Pelerine and Steve Smokey, Stanton Generating Station; Mark Strohfus, Great River Energy; ramsay Chang, EPRI, and Sharon Sjostrom, Tim Ebner and Rick Slye, Apogee Scientific, Inc.
2850	Michael G. Cashin, Minnesota Power (Allete)
2851	Melissa Davis
2852	Jed
2853	Douglas Henderson
2859	Anonymous
2860	John Benedict, Director, Division of Air Quality, West Virginia Department of Environmental Protection
2861	Michael W. Stroben, Duke Energy
2862	Kristine M. Krause, We Energies (no name in index)
2863	Robert E. Jordan
2864, 4138	Charles C. Bering, Watertown Citizens for Environmental Safety
2865	Anonymous
2866	Jane L. Harman, DVM

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2869	Julie Metty and Jo Ann Beckwith
2870	David Thomas, Alliance Coal, LLC
2872	Anonymous
2873, 2944, 2951	Sid Nelson Jr., Sorbent Technologies Corporation
2875	Michael T.W. Carey, Ohio Coal Association
2878, 4686, 4688-4696	Environmental Defense (National)
2879, 3476, 3451, 5478, 5547-5548, 5562, 5630, 5631	Neal J. Cabral, McGuireWoods LLP, on behalf of American Coal For Balanced Mercury Regulations (The Bituminous Coal Coalition)
2880, 2881, 3532, 1767	Thomas C. Synder, Director, Air and Radiation Management Administration, Maryland Department of the Environment; George S. Aburn, Maryland Department of the Environment
2882, 2885	American Public Power Association
2883	Peter Steitz, Wisconsin Public Power Inc
2884	Anonymous
2891, 4912, 4913, 4914, 4915, 5473	Rae E. Cronmiller and Bill Wernhoff, National Rural Electric Cooperative Association
2891	Rae E. Cronmiller and Bill Wemhoff, The National Rural Electric Cooperative Association
2895	Public Service Company of New Mexico
2897, 5466	Kennecott Energy
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2906, 3544	T. Ted Cromwell, Managing Director, Environment, American Chemistry Council
2907	Olon Plunk, Xcel Energy
2908	Melanie Homan
2910, 3404	Sheri-Ann Loo, Hawaiian Electric
2911	Louis P. Pocalujka, Consumers Energy
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2913	Manitowoc Public Utilities
2914	Sean Smith, Bluewater Network
2915	John Fainter, Association of Electric Companies of Texas
2916, 3515	Coal Utilization Research Council and Shannon M. Angielski, Coal Utilization Research Council
2917	Joel Schwartz, American Enterprise Institute
2918, 1434	David Steele, West Associates
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2971	K. Bidwell
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2981	William Scott Anderson
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2988	Amelia Minton
2989	Amy Martyn
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3005	Marilee B. Snyder
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3007	Michael
3008	Alex Ruprecht
3009	A.R. Martin, PhD
3010	Barbara Scott-Rarick
3011	Barb Juras
3013	Anonymous
3014	Barbara Drumeller
3015	Barbara Marzette
3016	Barbara E. Masters
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3029	Bill Bonte
3030	Bill Marsh
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3032	Barbara Swenson
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3035	Phyllis Doyle
3036	Bob Francey
3037	Bob Moser
3039	Gina Pisello
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3050	Melissa M.
3051	Carey Fitzmaurice
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3053	Doris Carlino
3054	Carlos Victoria
3055	Carol Nelson
3056	Carol Silber
3057	Carol Stewart
3058	Caroline Becker
3059	Carolyn Fisher
3060	Carolyn Maki
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3062	Catherine Wells
3063	Robert W. Buselmeier
3064	Charles Gallagher
3065	Charlene M. Key
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3068	Charles D. Johnson

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3084	William C. and Daily M. Stedman
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3103	David Peters
3104	David B. Pittard
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3106	Gregory A. Brentano Salem
3107	Debra Gehl
3108	Debra Rodman
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3129	Gene Featherstone
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3131	Fred Polvere
3132	Paul Funston
3133	Gary L. York
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3136	Gerri Plansker
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3139	Geraldine Bannister
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3150	Helen Barolini
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3152	Helen N. Hanna
3153	Herbert Parker
3154	Henry Rewun
3155	Howard Goldin, MD
3156	Howard Stahl
3157	Ian Duncan
3158	Ira Leidel
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3198, 3342	Marion Loonis, Executive Director, Wyoming Mining Association
3199	Christopher Jones, Director, Ohio EPA
3200	Paul E. Reynolds, Hoosier Energy Rural Electric Cooperative
3201, 3417, 4129	Gary L. Anderson, Plant Manager, Ebensburg Power Company
3202	Arthur J. Rocque, Jr., Connecticut Department of Environmental Protection
3204	Todd H. Haanes
3205	Montana Environmental Information Center/Rocky Mountain Office of Environmental Defense/Our Children's Earth Foundation
3208	Robert Norrgard, Western Fuels Association

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3209	Patrick Gregory, Ph.D., President, American Society of Ichthyologists and Herpetologists
3210, 3405	Erin M. Crotty, Commissioner, New York Department of Environmental Conservation
3211, 3507	Pete Homer, National Indian Business Association
3212	E. Clay Shaw, U.S. House of Representatives
3213	Joseph M. Garfunkel
3214	Dr. Keith M. Perrin, President, American Academy of Pediatrics
3214	Keith M. Perrin, MD
3215	Sandra C. Adams, Executive Director, MCH Coalition
3216	Marie and Ron Forman
3217	Carolyn F. Wilkerson
3218	Craig K. Breton, Santa Clara Valley Audubon Society
3219	Elina
3220	Rebecca A. Lexa
3221	Gary Young, Air Quality Division, Polk County, Iowa
3222	Ed Geiger, Frontier GeoSciences
3223	Debbie Netardus
3224	Mark Dayton, U.S. Senate
3225	Sherwood L. Boehlert, U.S. House of Representatives
3226	Patricia Garvey
3227	John J. McEneny, New York State Assembly
3228	Renee M. Espinosa
3229	Mike Kadas, Mayor, Missoula, Montana

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3231	Jill Young
3232	Craig Sharpe, Executive Director, Montana Wildlife Federation
3233	Dale Martinez, Governor, Pueblo of San Ildenfonso
3234	Deena L. Sprague
3235	Lloyd Doggett, U.S. House of Representatives
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3237	John Carter
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3240[2]	Jesse L. Jackson, Jr., U.S. House of Representatives
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3242[2]	James R. Langevin, U.S. House of Representatives
3243	Robert Anderson, MD
3244	Luke Metzger, TexPIRG
3245	Mike Turner
3246	Harry A. Olsen
3247[2]	Norm Coleman, U.S. Senate
3248[2]	Martin Frost, U.S. House of Representative
3249[2]	Jeff Bingaman, U.S. Senate
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3255	Anna Harlowe, Ecology Center of Southern California
3256	Lisa A. Cooney
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3258	Taylor Clemants
3259	Mary Frantz, PhD
3260	Daniel Schramm
3261	Andrea F. Nuciforo, Jr., Massachusetts State Senate
3263	Claudia A. Clifford, Montana Nurse's Association
3265[2]	Bill Nelson and Bob Graham, U.S. Senate
3266[2]	John H. McHugh and John E. Sweeney, U.S. House of Representatives
3267[2]	Collin C. Peterson, U.S. House of Representatives
3268[2]	Tom Allen and Michael Michaud, U.S. House of Representatives
3269[2]	Jan Schakowsky, U.S. House of Representatives
3270[2]	Hillary Rodham Clinton and Charles E. Schumer, U.S. Senate
3271[1]	M. Jane Cooper
3272[2]	Robert Brady, U.S. House of Representatives
3273	Donald R. Garlilt
3274	Martin Buck
3275	Marion Olson, President, Tinkers Creek Land Conservancy
3276[2]	Joseph Hoeffel, U.S. House of Representatives
3277[1]	Sandra Say
3278	Agnes L. West

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3281[2], 3357	John D. Dingell, U.S. House of Representatives
3282[2]	Tammy Baldwin, U.S. House of Representatives
3283[2]	John Lesch, Minnesota House of Representatives
3284	Elise Miller, Institute for Children's Environmental Health, Joint Comments of 8 Groups
3285	Michael Gochfeld, MD, Robert Wood Johnson Medical School, Environmental and Occupational Health Sciences Institute/NJ Task Force
3286	Hillary Rodham Clinton, U.S. Senate
3287	Barbara Boxer, James M. Jeffords, and Patrick J. Leahy, U.S. Senate
3288	Dave Freudenthal, Governor, Wyoming
3289[2]	Stephanie Gross, TexPIRG
3290	Patrick J. Leahy et al., U.S. Senate
3292[2]	Edward J. Markey, et al., U.S. House of Representatives
3293	Mark Kirk et al., U.S. House of Representatives
3294[2]	Matthew Dean, Physicians for Social Responsibility/ NYC
3295[2]	Raul M. Grijalva, U.S. House of Representatives
3296[2]	Northeast Partners for Mercury Reduction
3297[1]	Lelani Landis
3298[2]	Dakota Resource Council
3299[2]	David Wu et al., U.S. House of Representatives
3300	Amy Hohnowski, National Environmental Trust
3301[2]	Joseph Otis Minott, Clean Air Council, et al.

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3304	Eliot L. Engel, U.S. House of Representatives
3305	Millard Meyers, Executive Director, 1854 Authority
3306	John K. Alderman
3307	Keri Messina, Executive Director, New Hampshire Wildlife Federation
3308	William P. Krebs, Krebs and Sisler, LP
3309	W. Gladstone, MD, et al.
3310	Jenny Pike
3311	William E. Emery, President, Keweenaw Bay Indian Community
3312	Natalie Dube
3313	Richard M. Dailey, Mayor, City of Chicago
3314	Thomas P. DiNapoli, New York State Assembly
3316	Louise Bensen, Chairwomen, Hualapai Nation of the Grand Canyon
3317	Todd Halenbeck
3318	Sister Margaret Turk
3319	Liz Brater, Michigan State Senate
3321	Mary L Jenks, Chair of Air Pollution, Manasota
3322, 3349, 3354	Dr. Melanie A. Marty, Chair, Children's Health Protection Advisory Committee
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3323	Jim Gerlach, U.S. House of Representatives
3324	Rich Boucher et al., U.S. Congress
3325	Norman W. Deschampe, President, Minnesota Chippewa Tribe

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3330	Beth M. Mancuso
3331	Lisa M. Nnene
3334	Wendy Smith
3335	Norman Deschampe, Tribal Chairman, Grand Portage Reservation Tribal Council
3336	Paul O'Bryne, President, Florida Environmental Health Association
3337	James H. Douglas, Governor, State of Vermont
3338	Michael Noble, Executive Director, Minnesotans for an Energy Efficient Economy
3339	Donna Shanake
3340	Gifford Miller, New York City Council
3343, 3344	Bob Perciasepe
3347	Jim Cooper et al., U.S. House of Representatives
3348	Elizabeth Sword, Executive Director, Children's Health Environmental Coalition
3350	Greg Lake
3351[2]	Louise M. Slaughter, U.S. House of Representatives
3353	John M. Heuss, Air Improvement Resource, Inc.
3356	Patrick J. Leahy et al., U.S. Senate
3358	Henry A. Waxman and Tom Allen, U.S. House of Representatives
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3360	Elizabeth F. Nygaard

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3366	J. Nathan Noland, President, Indiana Coal Council Inc.
3367[1]	Virginia B. Haddens
3368	Judith Koral
3369	Linda Engard
3370	Paul Scott
3371	L. J. Gray
3372	Brij Naubria
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3393	Mike Hatch, Attorney General, State of Minnesota
3394	Lisa Madigan, Attorney General, State of Illinois
3395	Henry St. Germaine, Chairman, Lac du Flambeau Tribe
3396	John L. Carr et al., Catholic Coalition for Children and a Safe Environment
3398	Terry L. O'Clair, Director, Air Quality Division, North Dakota Department of Health
3399	Joan Brian
3400	Willie Braun, AES Warrior Run
3401	Anonymous
3402, 3406	Ronald Drewnowski, PSEG
3403	David N. Smith, Old Dominion
3412, 3413	John A. Mirabal, Governor, Pueblos of Taos
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3432	Harold M. Frank, Dairyland Power Cooperative
3433, 3434, 3435	J.P. Crametz, Oncept
3435, 3438, 3439, 4243-4252[1]	Carol A. Couch, Director, Environmental Protection Division, Georgia Department of Natural Resources
3436, 3437	Lori F. Kaplan, Indiana Department of Environmental Management
3440	Mary S. Miksa, Texas Association of Business
3443, 3407, 3408, 3409	John W. Shipp, Tennessee Valley Authority
3444	Randall R. LaBauve, FPL
3445	Charles R. Waklid, Progress Energy
3446	Stacey Davis, Center for Clean Air Policy
3452	Doug Bogen, New Hampshire Program Director, Clean Water Action
3457, 3527	James H. Schlender, Executive Administrator, Great Lakes Indian Fish and Wildlife Commission
3459, 4910	Clean Air Task Force et al Comprehensive Comments
3463, 3464	Jospeh G. Eutizi, San Miguel Electronic Cooperative
3465	Thomas B. Carter, Portland Cement Association
3467, 3468, 3469	Todd M. Myers, President, Westmoreland Coal Sales Company
3471	2 mass mailings
3472	88 mass mailings
3473	1,475 mass mailings
3474	10,187 mass mailings

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3508	Henrietta L. Wiley
3509	Matthew W. Ward, Spiegeland McDiarmid, Michigan Municipal Electric Association
3510	Victor G. Carrillo, Texas Railroad Commissioner
3511	Gordon Robertson and Tom Bedell, FishNet
3512	Appalachian Center for the Economy and the Environment
3513	Curtis Q. Warner, Arkansas Electric Cooperative Corp
3514	Jay Skabo, Montana-Dakota Utilities
3517	Greg Schaefer, Arch Coal Inc
3519	P.G. Para, JEA
3520	John L. Carr, U.S. Conference of Bishops Joint Comments
3522	Earnest E. Wessman, Pacificorp
3523	Laura Barker
3524	James L. Martin, President, 60 Plus Association
3525	Dee Martin, Council of Industrial Boiler Owners
3525	Robert Bessette, CIBO
3526	Bruce Niles, Sierra Club, Midwest
3528	Karen Kerrigan, Small Business Survival Committee
3529	Paul Hansen, Executive Director, Izaak Walton League of America

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3533	Bruce L. Rockwood, JD
3534	William B. Raney, West Virginia Coal Association
3535	Mary Beth Murphy, Supervisor, Town of Somers, NY
3537, 5474	Douglas J. Fulle, Ogelthorpe Power
3538	Eric V. Schaeffer, Director, Environmental Integrity Project
3543, 3544	Glenn Shankle, Acting Executive Director, Texas Commission on Environmental Quality
3546	Comment submitted by Richard M. Hayslip, Salt River Project
3547	Comment submitted by Patricia McCullough,Northeast Utilities Service Company
3548	J. Derek Furstenwerth
3549	George King, Chairman, Red Lake Band of Chippewa Indians
3550	Mille Lacs Band of Ohjibwe Indians
3551	Brandy Toft, Leech Lake Band of Ojibwe
3552	Stephen Mahfood, Director, Missouri Department of Natural Resources
3555, 3556	Louis P. Pocalujka, Consumers Energy
3559, 3560	Sheldon A. Zabel, Schiff Hardin, Southern Illinois Power Company Cooperative
3561	Tom Allen, U.S. House of Representatives
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3569	Adele Hilsen
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3675	Kay Gates, Sierra Club, Loxahatchee Group
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3682	Julie Pearson
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3685	K. Tulli
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4052	Stacy Bautista
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4054	Stanley Shaw
4055	Stephen Lutze
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4057	Steven Turtil
4058	Sue T. Parker
4059	Susan Sidney

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4060	Susan Dietrich
4061	Susan K. Beale
4062	Susan Heaney
4063	Suzanne Wienberg
4064	James Benthall
4065	Theresa White
4066	Therese Carson
4067	Tim Estes
4068	Tom
4069	Tom Ayers
4070	Tom Byrns
4071	Tom Sherlock
4072	Thomas and Joan McCullough
4073	Dr. Thomas Poulson
4074	Tracie
4075	Tracy K. Stillwell
4076	Anonymous
4077	John Turney
4078	Diane Valetta
4079	William Revet
4080	Marsha Andrews
4081	Warren Nelms
4082	William Sternman
4083	Bill Smalley

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4084	Wayne Mackeil
4085	Frank L. Mulhelm
4086	Anton J. Mraz
4087	S. Galen Smith, PhD
4088	Loraine W. Andrews
4089	Robert Zucchi
4090	Paul Jacobson
4091	David Addison
4092	45 mass mailings from Harvest Co-Op Markets
4093	103,274 mass mailings from MoveOn Org
4094	2 mass mailings from Left Corner Green Team
4095	6 mass mailings
4096	20 mass mailings
4097	Mr. and Mrs. Adams
4098	3 mass mailings
4099	99 mass mailings
4100	144 mass mailings
4101	316 mass mailings from Earth Tones, Green Alerts
4102	136 mass mailings from unknown, lignite
4103	49 mass mailings from Americans for Balanced Energy Choices
4104	2 mass mailings
4105	12,320 mass mailings
4106	2,610 mass mailings
4107	1,057 mass mailings from Clean Wisconsin

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4108	Helen K. Sexmer
4109	31 mass mailings from Audubon Society
4110	Celia Lambom
4111	George Milton
4112	Skip Kundahl
4113	Joe Gutkaski, President, Montana River Action
4114	Meghan Platek
4115	Lisa J. Whitmore
4116	Tina Norris
4117	Ed Mensah
4118	Barbara H. Lorenz
4119	Heather Nelson
4120	Margaret T. LoGalbo
4121	Allan T. Lacey
4122	Mark Hendrick
4123[1]	Charles McLaughlin
4124[1]	Jack Shaner
4125	Victoria P. Day
4126	Diane Ferraiolo
4127	Tex G. Hall, President, National Congress of American Indian
4128	Brooke Suter, Connecticut Director, Clean Water Action
4130	Audrey Leverton
4131[1]	David Nicholson
4132	Amy Wright, Dayton Power and Light Company

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4135[1]	Usha Turner
4136	R.L. Jeanes
4139, 4220, 4221	Steve E. Chester, Michigan Department of Environmental Quality
4140	3,292 mass mailings from Sierra Club, John Muir Society
4141	Edward Carnelli
4142	Forest Gee
4143	Paul Cipriano
4144	Fred H. Behnken
4145	1,318 mass mailings
4146	Marvin Dodge
4147	James D. Kotarski
4148	Thomas Denio
4149	Mark Miller, MD
4150	Malcolm Quint
4151	Geoffery M. Footner
4152	Michael Rufini
4153	Darlene Stengel
4154	Sheila A. Williams
4155	Benjamin Derrick
4156	John J. Gosling
4157	Craig R. Hannah
4158	Frank Damon
4159	Aaron Cloutier
4160	Ilene and Gaylord Younghein

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4161	Eric C. Rupp
4162	Elizabeth S. Merriam
4163	Lawrence Eugene Smith
4164	Holly Shisler
4165	Shanda Bowditch
4166	Premena
4167	Candence D. Schruber
4168	Mary Ellen Norman
4169	Judith B. Flemke
4170	Maureen Dodge
4171	Jay Simmons
4172	Marvin Dodge
4173	Steven Chan
4174	Jill Leelum
4175[1]	Paul Hedges
4176[1]	Bonnie Kay Howard
4177	Dawn R. Gallagher, Commissioner, Maine Department of Environmental Protection
4178	Emily Jo Goulden
4179	Richard French, Jr.
4180	Elizabeth Sibley
4181[1]	Jim Cusimano
4182	George and Dale. Davidson
4183	Bob and Helen Floyd

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4184	Jerome F. Downs
4185[1]	Buffy Francisco
4186[1]	Lois M. Schwarz
4187	Michael Buckley
4188[1]	Dale L. Koontz
4190	Colleen E. Swan, Tribal Administrator, Native Village of Kivalina
4191, 3554	John Fainter, Association of Electric Companies of Texas
4192	Jo Hanson
4193	72 mass mailings from Parkview Jr. High School
4195	Jane Garbacz
4196	Wesley Sweitzer
4197	Alma Avilla-Pilchman
4198	Jack Norman
4199	Glenn Gabryel
4200	Lara Shackelford
4201	Valerie Berk
4202	Mark Singer
4203	Dan and Leslie Schmidt
4204	Roger
4205	Barbara Dobos
4206	47 mass mailings from Paideia School
4207	Cathy M. Kennedy
4208	Anne Stern
4209	Peter J. Silverman

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4210	Megan Thomas
4211	Ellen Aiken
4212	Greg Roth
4213	Harry W. Read
4214	Jason P. McGraw
4215	Jane M. Heimlich
4216	Lorraine and Joseph Tash
4217	J.D. Dolan
4218	Neill De Paoli
4219[1]	Daniel J. Odistro
4223	Aldo B. Mysek
4224	Anthony Geron
4225	Robinson and Joan Lappin
4226	Chris Chesney
4227	David Viles
4228	Dena Hollowwood
4229	Jim and Diane Malcolm
4230	Douglas Harnby
4231	Ernie Herzberger
4232	Allan Frandsen
4233	Joe C. Gordon III
4234	Heather Williams
4235	Ann Coppola
4236	Jan Harmon

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4237	Nathaniel O. Keohane, PhD
4238	Mitchell Solovay
4239	Paul Martin
4240	Sunshine and Art
4241	R.J. Ruppenthal
4242	Anonymous
4253	Evelyn Green
4257	Jaime
4258	Darren Schmidt
4259	Sharrhan and Jonathan
4260	Lynn Martin
4261	Katarina Wittich
4262	Teresa McMichael
4263	Joyce R. Tomkins
4264	Clay Wickiser
4267	3 mass mailings from Belgrade Clinic, PLLP
4268	1,232 mass mailings
4269	91 mass mailings
4270	1,700 mass mailings
4271	6 mass mailings
4272	19 mass mailings
4273	9 mass mailings
4274	66 mass mailings
4275	1,170 mass mailings from League of Conservation Voters

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4276	300 mass mailings from Green Action
4277[1]	Michael Trunzo
4278	Michael Prewett
4279[1]	Foster S. Gray
4280	Margaret Williamson
4281	Jo Ann and John Zarins
4282	Ginger Hoffman
4283	Darren Williams
4284	Dean and Dran Reese
4285	Elizabeth Ketcham
4286	Sean Larkin
4287	Nola Davis
4288	Victoria Kelly
4289	Erich Baum
4290	Sandy O'Brien
4291	Victor Marrero
4292[1]	Lois Coleman
4293	Geert Aerts
4294	Ellen Hambrick
4295	Lois and Fred G. Andres
4296	Andrea Wilkus
4297	Zachary Lawson
4298	William and Irene Birge
4299	Douglas Norseth

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4300	Dennis P. Graham
4301	Julie Hynes
4302	John Dukovich
4303	Ron Sutherland
4304	Virginia Leech
4305	Lisa R. Sattler
4306	Leah Y.Y. Bravo
4307	Karen DiDomenicis
4308	Peggy Staton
4309	Susan Renison
4310	Eleanor Masheff
4313	J. Rodriguez
4314[1]	Jennifer A. Heindl
4315	Mary and Jack Palmer
4316[1]	Deborah Hayes
4319	Barbara Weyand
4320	Scott Jones
4321	Dennis Godburn
4322[1]	Marjorie Larson
4323[1]	Linda Claire
4324	George Papadi
4325	Jim Watson
4326	Reg Rollins
4327	George Ruth

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4328	Paul Clark
4329	Theresa Galvin
4330	Jim Borchert
4331	Carol Simonek
4332	Dale Drogseth
4333	Georgia Russell
4334	Bob and Ruth Johnson
4335	Jessica Alesandro
4336	Heather Beghtol
4337	Carol Geisler
4338	Kelly Varndell
4339	Don Von Ebers
4340	Ben Hauben
4341	Terry C. Collins
4342	Julia Sathler
4343	Dodi Reinoehl
4344	Ronald H. Janetzke
4345	Paige Eaton
4346	Gail Stidolph
4347	Rosario Martin
4348	David Eaton
4349	Tonya Martinez
4350	James Dunham
4351	Gregory and Ellen Erickson

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4352	Benjamin van der Veen
4353	Sue Peters
4354	Geoffery Bruce
4355	Janet Easter
4356	Mr. and Mrs. Paul Ingrisch
4357	Wayne Black, NMD
4358	Jacob Paul
4359	Karen Jane Peterson
4360	Kim White
4361	Leslie Limberg
4362	John Luther
4363	Michelle Walthall
4364	Anne Wood
4365	Kenneth Jones
4366	Laura Widman
4367	Patty Hoffman
4368	Anonymous
4369	Karen Cook
4370	John Kerry
4372	Jocelyn Parrish
4373	Jihn Deamon
4374	Connor Kerns
4375	Marilyn Beaver
4376	Marguerita Burke

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4377	Joe and Jill Collard
4378	Sandy Switzer
4379	Robert Thalmann
4380	Barbara Glenewinkel
4381	Michael
4383	John Gilhousen
4384	Brent Pharis
4385	David Gil
4386	Janey Lee
4387	Shari Johnson-Adams
4388	Peggy Dubach
4389	John Palmer
4390	William Peirce
4391	Heather Chapman
4392	Jim Pittman
4393	Andrew Wass
4394	Steve Moberg
4395	Barbara Hammond
4396	Kathleen
4397	Kyle Farley
4398	Patricia Nicely
4399	Pamela Deaton
4400	Eric Mankin
4401	Colleen J.G. Clark

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4402	Kim Kilman
4403	David K. Richardson
4404	Tiffani
4405	Mike Epa Chambers
4406	Paul Dirshka
4407	Barbara Berringer
4408	Paul Regan
4409	Patricia Wilz
4410	Dr. Cecilia Zuniga
4411	Ann Storie
4412	Pam Leis and family
4413	Cathy Fitzpatrick
4414	Kirby Hughes
4415	Jayne Tamburello
4416	Peter Taglia
4417	Diana Harris
4418	Stacy Wewe
4419	Fern R. Burgis
4420	Diane McCluskey
4421[1]	Nicholas Rosenstock
4422	Robert M. Hensley
4423	Anthony Napolillo
4424	Holly James
4425	M. Keleher

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4426	B. Sachau
4427	Jeffrey Cartwright-Smith
4428	J. Wang
4429	Lee Spivey
4430	Marcella Sarson
4431	Michael and Margie Myers
4432	Mary M. Downing
4433	Pete Esquiro
4434	Peter Mueller
4435	John Petrushka
4436	Rachel Myers
4437	Richard Bole
4438	Richard Schribner, MD
4439	Sarah Causey
4440	Sean Gutknecht
4441	Jane Alexander
4442	Tom Sanders
4443	Brendan Smith
4444	Deborah Vantreuren
4445	Karessa Townsend
4446	Carol Antill
4447	Marlene Satter
4448	John Duffield
4449	Diana V. Steel

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4450	Chris Zenos
4451	1,899 mass mailings from Southern Alliance for Clean Energy
4452	Lois M. Congdon
4453	Fay C. Graning
4454	Robert Manning, Florida Electric Power Coordinating Group
4455, 4456	John H. LeSeur, Hastings Utilities and City of Grand Island, Nebraska
4457	Holly Wise Rohrbach
4458	John T. Miller
4459	Denny Jernigan
4460	Barbara Moore Rumsey
4461	Nancy C. Tigner
4462	Helen Magnavita
4463	Martha Gidney
4464	Marlan Cooley
4465	Mark M. Giese
4466	R.J. Ruppenthal
4467	298 mass mailings
4468	Ali Ariniega
4469	Gene Winter
4470	Patsy S. Crosby
4471	Susan Lucalio
4472	Megan E. Furniss
4473	Marya Howell-Carter, PhD
4474	Lucia L. Armstrong

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4475	Jonathan Coss
4476	D. Clark Boykin
4477	R. Imogene Gotchall
4478	Anna Harlowe, Ecology Center of Southern California
4479	Phillips R. Goldsworthy
4480	Sheryl Scott
4481	Richard Sarertsky
4482[1]	Peggy Schmidt
4483	Elizabeth Ketcham
4484	Sylvia Hazlehurst
4485[1]	Jim Odgen
4486	Charles P. Rfau
4487	Charles W. Larson
4488	Thel Dominici
4489	Jeanne Rehwinkel
4490	Kathy Woods
4491	Chrys Gardener
4492	Robert Shaffer
4493	Beverly Shaffer
4494	Casey Hemhyles
4495	Laura McMurray
4496[1]	A.A. Allen
4497	Michael G. Polski
4498	Allen Tindell

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4499	Robert Giambalvo
4500	Maryanne Owens
4501	George M. Spoon
4502	Greg Matza
4503	Randall E. Hartman
4504	Rodney Baumbach
4505	Mary Anne Guggenheim, MD
4506	Carol Siewert
4507	Anthony Countey
4509	JoAnn Nishiura
4510	Barbara L. Black
4511	Bryan Brodie
4512	Gail Arnault
4513	Kevin Fischer
4514	Elise Harvey
4515	Lynnette Rizek Hanne
4517	Danny Thorpe
4518	Robert D. Britz
4519	Lynn Morell
4520	Edward Darmohray
4521	Harold J. Liebrecht
4522	Mary Schrunk
4523	M. Hessek
4524	Carol Davis

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4525	Donna Tamres
4526	Loreen Spangler
4527	Joanne Mann
4528	Suzanne and Allen Bassin
4529	Gloria Dunn
4530	Jim Pittman
4531	Maxine
4532	Bernie Johnson
4533	Donna Ridgeway
4534	Jesus Camarillo
4535	Susan Barker
4536	Sunny Julius
4537	Jane Kovac
4538	Kathy Johnson
4539	Susan Loperete
4540	Margaret Ellis
4541	Deborah Oliff
4542	Christina Martin
4543	Dean Zagone
4544	Patricia Ohnikian
4545	Adina Warren
4546	Janet Accardi
4547	Raymond A. Firestone, PhD
4548	Teresa Jones

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4549	Rebecca Hierholzer
4550	Judith B. Halloran
4551	Debbie Plumley
4552	Joseph Monaghan
4553	Carey Crist
4554	Dr. John L. and Susan Robertson
4555	Shelly Boose
4556	Chuck and Kathy Brinkman
4557	Jamie Pogach
4558	Jerry Young
4559	Lorna
4560	Nicole Ramos
4561	Karen Gonzalez
4562	David Hilger
4563	Yvonne Britt
4564	Rad Benson
4565	Lori D. Tripp
4566	Joe Garisson
4568	Dayna Dunbar
4569	Brian G. Supplee
4570	Charles Harwood
4571	Gila Markov
4572	Dale Green
4573	Sarah Mauney

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4574	Nyla Fonger
4575	Joanne Carolan
4576	Marjorie J. Walters
4577	Iris Lonker
4578	Dorothy Fairweather
4579	Jerry Spalding Fredin
4580	Kim Sterner
4581	Joan Russell
4582	Helen Melvin
4583	Ellen Levy
4584	Linda Fisher
4585	Debbie Hemlock
4586	Timmy Chen
4587	Tracy Carlson
4588	Barbara Sheeley
4589	Hal Baden
4590	Carolyn Cole
4591	J. Kirk and Marcay Dickens
4592	Lois and Marvin Barger
4593	Ann Storie
4594	Bea Ann Bridges
4595	Trevor J. Owen
4596	Laura Wolf
4597	Lisa Marshall

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4598	Kim Dunn
4599	Lisa Edwards
4600	Stacey Kirms
4601	RaDonna Roland
4602	Catherine Sumners
4603	Meggan McEvoy
4604	Ruth Ann Humphrey
4605	Patricia Williams
4606	Irma Call
4607	Rosalind Mearns
4608	Ruth McIntosh
4609	Richard C. Stancliff
4610	Ed Masters
4611	Suzanne Skinner
4612	Frenesa K. Hall, MD
4613	Paul Regan
4614	Frances K. Tetens
4615	Tom Sheeley
4616	Tony Siegle
4617	Wilson Bryan
4618	The Ward Family
4619	Peggy Lee
4620	Anonymous
4621	Anonymous

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4622	Lin Hall
4623	Thomas C. Maurer
4624	Betty Jennings
4625	Jennifer B. Frazier
4626	Bernadine Rettger
4628	Elizabeth Ward
4629	Bridget Fonger
4630	June Davis
4631	Pamela Gale Park
4632	Loraine Scime
4633	Shelly Tracy
4634	Marilyn Cuffee-Gordon
4636	Lisa O'Neil
4637	Phyl Morello
4638	Dwayne Tuttle
4639	Kathleen Gabriel
4640	John and Verna Wright
4641	John Dziak
4642	Kayde Cadwell
4643	June Foster Stinson
4644	Glormil
4645	David Turnbell
4647	Anonymous
4648	Galen and Paula

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4649	Rick Temple
4651	Cara Gifford
4652	Christine Rogers
4653	253 mass mailings
4654	Peggy Lee
4655	Peter McClelland
4656	A.J. Maimbourg
4657	Carolyn G. Crombie
4658	Aaron Dougherty
4659	76 mass mailings from Illinois PIRG and Education Fund
4660	10 mass mailings from PIRG Michigan
4661	183 mass mailings from League of Conservation Voters Education Fund
4662[1]	15 mass mailings
4663	3 mass mailings from Sierra Club
4664	11,717 mass mailings
4665	15 mass mailings
4666	390 mass mailings from Sierra Club
4667	1,330 mass mailings from SC Partnership
4668	194 mass mailings
4669	150 mass mailings from Environmental Maine
4670	5 mass mailings from Environmental Maine
4671	283 mass mailings
4672	1,379 mass mailings from Wisconsin Earth Day Coalition

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4673	82 mass mailings from Sierra Club North Star Chapter
4674	902 mass mailings from League of Conservation Voters Education Fund
4675	927 mass mailings from Montana PIRG
4676	2,540 mass mailings from Save the Clean Air Act Organization
4677	870 mass mailings Penn Environment
4678	4,101 mass mailings from Environment Colorado
4679	6,086 mass mailings from Environment California
4680	120 mass mailings from Illinois PIRG and Education Fund
4681	7,644 mass mailings from Penn Environment
4682	9,956 mass mailings from State PIRGs
4683	10,407 mass mailings from Sierra Club
4684	114,639 mass mailings from State PIRGs
4685	2,358 mass mailings
4697	Kirk Freundenburg
4698	Ann Wilsnack
4699	Anne Wood
4700	Bob Bramblett
4701	Carey Crist
4702	Charlene Woodcock
4703	Cheryl Heath
4704	Sean McCandless
4705	Crystal Bevans
4706	Cyane Gresham

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4707	Dave Daulton
4708	David K. Richardson
4709	Anonymous
4710	Dennis Dimster
4711	Derek McLaughlin
4712	David Giffen
4713	Edward Askew
4714	Debra Shankland
4715	David Keller
4716	Jim Miller
4717	Howard Edson
4718	Jay and Lucia Weinroth
4719	Jeff Lane
4720	Jessica Murdaugh
4721	Joe Jennings
4722	Keith Brown
4723	Karen L. Hansen
4724	Kirk Freudenburg
4725	D. Keith
4726	Katherine Duncanson
4727	Ken Thygerson
4728	Marla Rolfe
4729	Megan Harris
4730	Melissa Powers

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4731	Tawny Mata
4732	Michael Bennett
4733	M.J. Gardner
4734	Nancy Kessler
4735	Nita Ferguson
4736	Melissa J. Brenneman
4737	Ellen Weiner
4738	Amanda Leogue
4739	Ragen Tilzey
4740	Ralph Klawitter
4741	Steven Rychnovsky
4742	Chuck Swensen
4743	Vickie Bielanski
4744	William G. Wales
4745	Patricia DeMarco-Rowe
4746	Tanya Dobbs
4747	Ann Rumrill
4748	Pamela Heskett
4749	Linda Rose
4750	4 mass mailings
4751	Marybeth Clark
4752	Janet Gilbert
4753[1]	Ginny Mayhew
4754	7,399 mass mailings

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4755	Thomas Stiles
4756	Michael Peltneir
4757	R.H. Williams
4758	Ginny Corzire
4759	Peggy Louise Daulton
4760	Joline Bettendorf
4761	Nancy Schiegg
4762	Claire Iverson
4763	Lee Walker Oxenham, Patapsco Riverkeeper
4764	Robert Rutowski
4765	Kate Godfrey
4766	Tania Banak
4767	John Ulloth, Sierra Club, Angeles Chapter
4768	Marion Thorne
4769	Allan H. Messinger
4770	Carmen Pirotte
4771	Jim Sconyers, Sierra Club, New Hampshire
4772	Alan C. Hasselwander
4773	Anabell Kinney
4774	Anita Moris
4775	William DeForest
4776	Bonita DiGennaro
4777	Carol Vericker
4778	Charles M. Paden, PhD

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4779	Claire Hartford Hornsten, President, Women's Public Forum
4780	John Garret Baker
4781	D. Meehan
4782	Gwenyth M. Nichols
4783	David Kohn
4784	Dru Carter
4785	Matthew and Elizabeth Stein
4786	Erin Maloney
4787	Eve Fox
4788	Glenna Lea Citron
4789	Gwynne Brown
4790	Henry Massery
4791	Janis Haansen Klinger
4792	Jewel Down
4793	Kimberly Murphy
4794	John Thornberg
4795	Claude Roland, MD
4796	Jonathan Davids
4797	Kenneth Hill
4798	Kyle Farley
4799	Kristen J. Garrett
4800	Lawrence D'Arco
4801	Amy Rudson
4802	Christine Dawkins

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4803	Meggen Harris
4804	Amanda O'Hearn, PhD
4805	Patrick Marcell
4806	Paul Crouser
4807	Stephen and Ann Devitt
4808	Peter Lee
4809	Pierre Musy
4810	Russell Behrman
4811	Robert H. Delves
4812	J. Richard Manier, Jr.
4813	Ronald Harris
4814	Rosario Martin
4815	Rosemarie M. Jeffery, MD
4816	Ruth Kuhfahl
4817	Geoffrey Greene
4818	Susan Localio
4819	Todd D. Johnson
4820	Dr. Peter J. Veverka
4821	Vicki Stephens
4822	Marcy Bode
4823	William and Margo Cooper
4824	Rozane Williamson
4825	Amanda Chrisp
4826	Herb Mintz

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4827	Sharon Wang
4828	Marian Hackney
4829	John de Souza
4830	Steve Blum
4831	Doug Poole
4832	Mel and Gail Minthorn
4833[1]	Nicholas Rosenstock
4834	Michael J. Mayo
4835	Benjamin Allen
4836	April Ford
4837	Barbara Presson
4838	Anonymous
4839	Ben and Stacy Merrick
4840	Bruce L. Renguist
4841	Chris Mihill
4842	Gertrude Freidel
4843	Lona Rosenfeld
4844	Dan Schotter
4845	David Weitzler
4846	Donna J. Williams
4847	James Wilson
4848[1]	Marjorie Larson
4849	Linda S. Sanders
4850	Karen Cowdrey

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Docket ID No. OAR-2002-0056	Commenter
4851	Milton Hanzel
4852	Evan Francis
4853	Nancy Matyasovsky
4854	Peggy Kyprianides
4855	Susan Bawin Coonradt
4856	Robert Lowery
4857	Patricia Nicely
4858[1]	Tim Lingg
4859	Todd Bradshaw
4860	T. Reid Kavieff
4861	Jill
4862	Christine R. Masterson
4863	Homer J. Hall
4864	Jackie Needleman
4865	Pete Jimenez
4866	Mr. and Mrs. Martin Glynn
4867	33,498 mass mailings
4868	502 mass mailings
4869	31 mass mailings
4870	Neila Jack
4871	2 mass mailings
4872	10 mass mailings
4873	22 mass mailings
4874	82 mass mailings

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
4875	374 mass mailings
4876	34 mass mailings
4877	78 mass mailings
4878	3,656 mass mailings
4879	279 mass mailings
4880	100 mass mailings
4881	29 mass mailings
4882	11,849 mass mailings
4883	16,667 mass mailings
4884	3 mass mailings
4885	981 mass mailings
4899	Gil Freedman
4900	Anonymous
4901	Chris Robbins
4902	Kathy Knudsen
4903	Paul Thib
4905	Ann Walton
4906	Mike Shifflet
4907	13 mass mailings
4908	Jennifer Garrick
4936	Kevin Fitzpatrick
4937	Jeanette Hartge
4938	Marc B. Horin
4939	Nicholas Shestople

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
4940	Mike Jones
4941	Ben Eubanks
4942	Kristen Rachford
4943	Frances E. Harkins
4944	Anonymous
4945	Denise Brown
4946	Anonymous
4947	Holly Terschuur
4948	Marilyn Brittner
4949	Sharon L. Oler
4950	L. Evelyn Beason
4951	James B. Mitchell, PhD
4952	Carolyn Ulrich
4953	Anne M. Hanada
4954	Lois Miles and family
4955	Juanita Wright Potter
4956	Patricia A. Baldwin
4957	Buck O'Herin
4958	Mariel E. Matthews
4959	Faith Helen Farris
4960	Dr. Andrew Millard
4961	Linda Davis
4963	4 mass mailings
4964	750 mass mailings

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
4965	Carol E. Colip
4966	Joan Sprague
4967	Peter W. Joseph, MD
4968	Dorothy Horton
4969	T. Hudson
4970	Mark Potter, MD
4971	Tom Aldridge
4973	Carol Long
4975	3 mass mailings
4977	Sean Palfrey, MD
4978	Rachael Blumenthal
4979	Anne C. Godfrey
4980	Rhoda Lonow
4981	Janet M. Redding
4982	Pamela P. McVety
4986	James A Rapp
4987	Fayetta P. Weaver
4988	Marjorie M. Donn
4989	2 mass mailings
4990	Nancy Corson Carter
4991	M.D. Hanson
4992	Marilyn Jacobs
4993	Anonymous
4994	Amber Powers

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
4995	Danna P. Murch
4996	Nancy dell'Aquilla
5002	Nathan Pierce
5003	Judi Keppler
5004	Sam West
5005	Elaine Storella
5006	Jessie Magnuson
5007	Christie Thomas
5008	Tetsa Skordos
5009	Joy Peterson
5010	Leighanna Kelley Midkiff
5011	Tom McDonnell
5013	Doris Hartman
5014	Phyllis F. Campbell
5015	Susan Bergmann
5016	J.C. Englert
5017	Helen Jo Williams
5018	Darlene Wagner
5019	Karl B. Bucholz and Karen H. Robinson
5020	Jane Krentz
5021	Allen Davisson
5022	Gil Freedman
5023	Anonymous
5024	Chris Robbins

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
5025	Kathy Knudsen
5026	Paul Thib
5027	Nicholas S. Carpenter
5028	Richard Holt
5029	Karen Meyer
5030	Glen Becker
5031	Kristy Hartje
5032	Camille Holthaus
5033	Margaret Young
5034	Marc Polansky
5035	Elizabeth Cohen
5036	Hilary Lorraine
5037	Karen Luepke
5038	Christen C. Garrett
5039	Robert F. Delaney
5040	Andrew J. Spano, Westchester County Executive, NY
5041	Stephanie Klotz
5042	Wendy Tokuda
5043	Katie Phipps
5044	Tatyana Livshultz
5045	Mike Shifflet
5046	Janet and Donald Mackenzie
5047	Christina Hasseth
5048	M. Levy

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
5050	Bob Taft, Governor, Ohio
5051	Patrick Leahy, et al., U.S. Senate
5052	Alabama Waterfowl Association
5053	National Wildlife Association
5054	Victor Carrillo, Texas Railroad Commission
5055	Robert and Geraldine Folz
5056	David C. Foerter, Institute of Clean Air Companies
5057	Audrey Falcon, Chief, Saginaw Chippewa Indian Tribe
5058	Ian Nelson
5059	Jane Hagrave
5060	John Osner
5061 D	Mass campaign, Sierra Club
5062	Christopher Hord, Sierra Club, Georgia Chapter
5063 D	Mass campaign, Wisconsin Earth Day Coalition 2004
5064 D	Mass campaign, Penn Environment
5065 D	Mass campaign, Environment California
5066 D	Mass campaign, Environment Colorado
5067	Chris Spalding
5068 D	Mass campaign, LCV Education Fund
5069	Dr. Charles Powers, NY Academy of Sciences
5070	Edger P. Stegmann
5071	J. Sipkins
5073	2657 mass campaign, Greenpeace mailings
5073	Brandy Toft, Leech Lake Band of Ojibwe

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
5074	404 mass campaign mailings
5075	833 mass campaign mailings, Audobon Ohio et al.
5076	George and Myra Hurst
5077	Miriam L. Wolin
5078	Barbara Greenman
5079	Annette Wilber
5080	Ethel M. Kinkaid
5081	James E. Wagner
5082	Candice Peters
5083	Jan Rice
5084	John Paniperin
5085	Ann Regel
5086	Richard A. Kendrick
5087	Pedro L. Lanabina
5088	Sue Lorens
5089	Randy Heidenfelder
5090	Mary L. Roark
5091	Ruth Niswander
5092	Valeri McCaly
5093	Dan Feiertag
5094	Barry Fansher
5095	Barbara Hillhouse
5096	Liis McKenna
5097	Evelyn N. Brew

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
5098	Bruce Pisby
5099	Nancy B. Delaiti
5100	Shari Bachmann
5101	Robert M. Hensley
5102	Laura Manthe
5103	Anonymous
5104	James Coes
5106	Brandon R.
5109	69 mass campaign mailings
5110	66 mass campaign mailings
5111	Donald Manzull, U.S. Congress
5124	Maria Van Kirk
5126	16 mass campaign mailings
5128	25 mass campaign mailings
5129	9,231 mass campaign mailings
5130	Richard Smith
5131	Craig Overbeck
5132	Marc Stein
5133	Theresa Neuroth
5134	Julie Sutor
5135	Kris Medic
5136	Ken Mosher
5137	Rollin Newcomb
5138	Patricia Miller

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
5139	Eun Swansong
5140	Anonymous
5141	Anonymous
5142	Nicholas Engelfried
5143	John Bollinger
5144	Tina Engelfried
5147	Janice Watten
5149	Anonymous
5152	7 mass campaign mailings
5153	5 mass campaign mailings
5154	7 mass campaign mailings
5155	17 mass campaign mailings
5156	1,579 mass campaign mailings
5157	18 mass campaign mailings, Little Chute Elementary School
5158	George A. Jones
5159	Brandon Aikin
5160	Eloise Heimann
5161	Susan Scheppler
5162	Jessica Moy
5163, 5165	Ted Light
5166	William Huggins
5167, 5174	Paul Cowden
5187	1 mass campaign mailing
5193	Rosemary Engelfried

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
5194	Renae Robertson
5195	Billie Robertson
5198	Roger Hoffman
5199	Ted Beringer
5200	Anonymous
5253	1,161 mass campaign mailings
5254	Tina Spears
5258	124 mass campaign mailings
5260	Ellen Lougee
5261	David Leithhauser
5264	Irene Lieberman
5266	Robert Hunter
5267	Diane Sklensky
5268	Karin Kirulis
5269	Lynn Kinnucan
5270	Bassam Imam
5271	Jerise Fogel
5272	Alaina Borget
5273	Robert A. Mertz
5274	James Swaney
5275	Judith Gilliland
5276	Carey Blanchard
5277	Susanna Levin
5278	Dr. Carole Warner

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
5279	James Berg
5280	Karin Kvale
5281	Diana Varley
5282	The Clean Energy Group
5283	Tressa Schendel
5285	Chris Wells
5286	William Robens
5287	Laura E. Tudor
5288	Eric Zuber
5289	Ron Hildebrand
5290	Mary Young
5291	Dawn Brennan
5292	Althea Godfrey
5293	Patricia Archbold
5294	Suzanne Marckx
5295	K. Oneill
5296	Craig Scheunemann
5297	John Phillips
5298	Sandra Collins
5299	Max Hemmert
5300	David Fitzjarrell
5301	Liz Lundberg
5302	Dr. Wendy.Yona Noon
5303	812 mass campaign mailings

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Docket ID No. OAR-2002-0056	Commenter
5304	105 mass campaign mailings
5305	Beth Hamilton
5306	Roy Fouts
5307	Robert Shroy
5308	Robert Mossman
5309	Lynell Martinez
5310	Joe Culbertson Jr.
5311	Fred Vanderbeek
5312	Erica Schwartz
5313	700 mass campaign mailings, Clean Wisconsin
5315	Brandon
5316	Peter Garrett
5317	Susan Miller
5318	Brian Scott
5319	Michael Fiori, MD
5320	Mary Ann Maxson
5321	John Witte, Ph.D
5322	Monique Maisenhalter
5323	Gerrit Crouse, Ph.D
5324	Milan and Patricia Murchek
5325	Jay Allaire
5326	Ann Modro
5327	Matt Roman
5328	Pat Gallagher

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Docket ID No. OAR-2002-0056	Commenter
5329	Arthur Gilbert
5330	Delwin Johnson
5331	Heather A. Ridle
5332	The Clean Energy Group
5333	Anonymous
5334	Terry Travers-Davin
5335	Hilda Knowles
5336	Anonymous
5348	Priscilla Ivester
5349	Wendy Rosenau
5350	Erin Morgan
5351	Daniel Dougherty
5352	Chris Baeckstrom
5353, 5354	Lorri Carrell
5355	Anonymous
5356	Bernadine Bellmor
5357	Anna Gray
5358	Kathy Dato
5359	Victoria Hager Rose
5360	Chuck Abbate
5361	Doug Fogel
5362	Melissa Hester
5363	Henry Schrieber
5364	Robert Reed

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Docket ID No. OAR-2002-0056	Commenter
5365	Bryant C. Danner, Edison International
5366	Stephen Johnson
5367	Wanda S. Ballentine
5368	James Jenkins
5369	Bev Stadick
5370	Robert L. Powers
5371	Julian Huerta
5372	Jesse Ayotte
5373	Nori Muster
5374	Ann Isaksen
5375	Bob Barcus
5376	137 mass campaign mailings, Sierra Club
5377	Eugene Dallas Gay
5378	Seth M. Robbins
5379	J. Michael Reisert
5380	William C. Mahaffey
5381	Michael L. Gourley
5382	Arthur F. Kistler
5383	Neil Anthony Busche
5384	Donald H. Miller
5385	Kathleen Doris Janacek
5386	Sean Conley
5387	Jeff Leibfreid
5388	Luke Allen Russell

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Docket ID No. OAR-2002-0056	Commenter
5389	Joe Roger
5390	Mrs. Marian Buckner
5391	Clarence A. Petty
5392	James
5393	Cynthia Kobak
5394	Candice Peters
5395	Susan Scheppler
5396	R. Allen
5397	Ann Regel
5398	Barbara Voelker
5399	Bonnie J. Walling
5400	Luann Lindstrom
5401	Doug LaFullette
5402	2,100 mass campaign mailings, Sierra Club
5403	Whitney Parks
5404	John L. Stowell, Cinergy Corp
5405	Anonymous
5406	Edward J. Barton
5407	Aishaa Abdul-Karim
5408	Deb Belmore
5409	Michele Theberge
5410	Linda Foster
5411	Jeff Quick, Utah Geological Survey, Utah
5412	Pauline Blocker, President, Save Our Sea Life Org, Inc.

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Docket ID No. OAR-2002-0056	Commenter
5413, 5414	Jane K. Stahl, Connecticut DEP
5415	Cassidy Weyel
5416	Margaret Manzo
5417	Pala
5419	Pat
5420, 5565	John A. Paul, RAPCA
5421	Kevin Donnelly and John Belvins, Connecticut DNREC
5422	Charles B. Sedman, Consultant and Willard L. Goss, RJM-Beaumont
5422	Robert L. Kappelman, Florida Municipal Electric Association Large Generator Coalition
5422	Robert L. Kappelmann, Florida Municipal Electric Association Large Generator Coalition
5423	Robert Ferguson, Center for Science and Public Policy
5424	Catherine Gay
5425	Robert F. Gruenig
5426, 5427	Charles B. Sedman, Consultant and Willard L. Goss, RJM-Beaumont
5428	Charles T. Phillips
5429-5440	ADA Environmental Systems
5442	Robert Ferguson, Center for Science and Public Policy
5443, 5461-5463	Robert W. Golledge, Jr., Massachusetts DEP
5444	Anonymous
5445	Michael L. Marvin, Business Council for Sustainable Energy and John W. Jimison, U.S. Combined Heat and Power Association
5446	Mark H. Davies, Kennecott Energy Company
5447	Frederick D. Palmer and Rogert B. Walcott, Peabody Energy

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Docket ID No. OAR-2002-0056	Commenter
5448	S. Morgan
5449	Ingeborg Eibl
5450-5454	Dr. Leonard Levin, Electric Power Research Institute
5455, 5512, 5513	Christine Berini, Fond du Lac Band of Lake Superior Chippewa
5455	Michael L. Marbin, Business Council for Sustainable Energy and John W. Jimison, US Combined Heat and Power Association
5456	Joe L. Citta, Jr., Nebraska Public Power District
5457, 5459, 5510	A. Todd Johnston, National Mining Association
5458	Carl Johnson, New York State Department of Environmental Conservation
5460, 5514, 5515	Eliot Spitzer, New York Attorney General; Richard Blumenthal, Connecticut Attorney General; Thomas F. Reilly, Massachusetts Attorney General; Connecticut Attorney General; Kelly A. Ayotte, New Hampshire Attorney General; William H. Sorrell, Vermont Attorney General; and Peggy A. Lautenschlager, Wisconsin Attorney General
5464	Nancy L. Seidman, STAPPA and Dennis J. McLerran, ALAPCO
5465-5468	Catherine A. O'Neill, Center for Progressive Regulation
5469	Quinlin J. Shea, Edison Electric Institute
5470	Charles Richardson
5471	Class of '85 Regulatory Response Group
5472	William Rogers, Detroit Edison Company
5473	National Rural Electric Cooperative Association
5474	Douglas J. Fulle, Oglethorpe Power Corporation
5475	Kathleen A. McGinty, Pennsylvania Department of Environmental Protection
5476	Charles J. Lippert, Mille Lacs Band of Ojibwe Indians

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Docket ID No. OAR-2002-0056	Commenter
5477, 5479, 5480, 5481, 5483	Northeast States for Coordinated Air Use Management (NESCAUM)
5478, 5547, 5548, 5562, 5630, 5631	Neal J. Cabral, McGuireWoods LLP, for American Coal for Balanced Mercury Regulation (The Bituminous Coal Coalition)
5482	John W. Dwyer, Lignite Energy Council
5484-5487, 5489	C.M. Hobson, Southern Company
5488	Environmental Defense et al
5490	Shawn Glacken, TXU Power
5491, 5623, 5628, 5629	Sid Nelson Jr., Sorbent Technologies
5492	Bill Hoback, Illinois Department of Commerce and Economic Opportunity
5493	Edward C. Sullivan, AFL-CIO
5494	C.V. Mathai, Arizona Public Service Company
5495	Tractebel Power Inc
5495	Tractebel Power Inc.
5496	Michael G. Cashin, Minnesota Power Company-Allete
5497	Hunton and Williams LLP for Utility Air Regulatory Group
5498, 5499, 5501	Bill Edmonds, WEST Associates
5500, 5591	David C. Foerter, Institute for Clean Air Companies
5502	Richard Carlton, Paul Chu, Leonard Levin, George Offen, and Janice Yager, Electric Power Research Institute
5503	Susan Ford
5504, 5505, 5508, 5511	Alan E. Bland, Subbituminous Energy Coalition
5506, 5507	Brandy Toft, Leech Lake Band of Ojibwe

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Docket ID No. OAR-2002-0056	Commenter
5509	Terry R. Yellig, Sherman, Dunn, Cohen, Liefer and Yellig for AFL-CIO
5516, 5517	William L. Kovacs, U.S. Chamber of Commerce
5518-5530	Jeffery T. Underhill, New Hampshire Department of Environmental Services
5534-5540	Jon Devine, Natural Resources Defense Council
5542	Marshall E. Whitenton, National Association of Manufacturers
5543 5544	John W. Shipp, Jr., Tennessee Valley Authority
5545, 5546, 5590	Michael J. Nassi and Lloyd Gosselink for Gulf Coast Lignite Coalition
5550, 5551-5554	William O'Sullivan, New Jersey Department of Environmental Protection
5556, 5557	Steven E. Chester, Michigan Department of Environmental Quality
5558, 5559, 5589	Al Shea, Wisconsin Department of Natural Resources
5560, 5561	Edward A. Helme and Stacey E. Davis, Center for Clean Air Policy
5563	J. Stephen Hartsfield, National Tribal Air Association
5564	Joseph E. Euitizi, San Miguel Electric Cooperative, Inc.
5566	Felice Stadler, National Wildlife Federation
5567	3 mass campaign mailings
5568, 5569	Gypsum Association
5570	Melanie A. Marty, Children's Health Protection Advisory Committee
5571	Therese Pugh, American Public Power Association
5572	95 Mass campaign-State PIRGs
5573	Anonymous
5574	Thomas Glynn El
5575	Alma Smith

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Docket ID No. OAR-2002-0056	Commenter
5576	John Pamperin
5578	Carla D. Hanson
5579	Edward A. Pahnke
5580	Carol Wilson
5581	Jack Litka
5582	Tom Tomilson
5583	Michele E. Mukatis
5584	April Stouffer
5585	Diane G. Conway
5586	J.W. Ward
5587	Paul Cardran
5588	Helen Kalin Klanderud, Mayor, Aspen, Colorado
5592	2 mass campaign mailings, Sierra Club
5593	Bengt and Polly Ohman
5594	P. Vilinsky
5595	Cynthia Leahy
5596	Mindy Drossner
5597	Lillian and Charles Rhinehart
5598	Elizabeth Watts
5599	Miriam L. Wolin
5600	Richard Samuels
5601	Thomas Aldridge
5602	Marilyn R. Cornelius
5603	Kathryn Wild

Table A-1 (Continued)

Docket ID No. OAR-2002-0056	Commenter
5604	Daniel Byrd et al.
5605	Myfanwy Plank
5606	Marilyn Hamete
5607	Robert Francis Piazza
5608	Kathy Harty
5609	L. Jean Anderson
5610	Arthur O. Long
5611	Eleiza Parkson
5612	Marlene Boecken
5613	Jim DeCecco
5614	Paula Cardia
5615	Clerence Guerin
5616	Francis Volpe
5617	Violette B. Van Belle
5618	India Loevner
5619	Terrie Derstine
5620	Sharon Ford
5621	Kathleen Bailey
5625	Judy Valentine
5626	URS Group et al.
5627	Duke Power et al.
5632	Anonymous
5633	D. Roxey
5634	L. Wooldridge

Table A-1 (Continued)

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5768	Record of telephone comments received, weeks of March 29-June 18, 2004

[1] Not applicable (Interstate Air Quality Rule, New Source Review, Clean Air Planning Act, CAFÉ standards, nuclear waste).

[2] Request for public hearing and/or extension of comment period.

[3] Public hearing testimony (Chicago, IL; Philadelphia, PA; Research Triangle Park, NC; or Denver, CO).