American Public Power Association

APPA's comments on

National Emission Standards for Hazardous Air Pollutants from Coal-and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units

(NESHAP Proposal Also known as EGU MACT or Mercury HAPs Proposed Rule)

Docket Number EPA-HQ-OAR-2009-0234;

Docket Number EPA-HQ-OAR-2011-0044, RFL-9286-1

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About APPA

The American Public Power Association (APPA) is the national service organization representing the interests of the more than 2,000, not-for-profit municipal and other state and local community-owned electric utilities that collectively provide electricity to approximately 45 million Americans. These utilities, or "public power" systems, are among the most diverse of the electric utility sectors, representing utilities in small, medium and large communities in 49 states (all but Hawaii). Seventy percent of public power systems are located in cities with populations of 10,000 or less. APPA was created in 1940 as a non-profit, non-partisan organization. Its purpose is to advance the public policy interests of its members and their consumers, and to provide member services to ensure adequate, reliable electricity at a reasonable price with the proper protection of the environment.

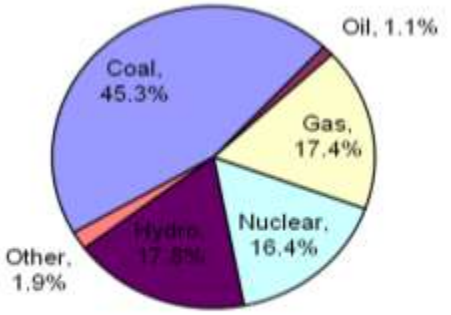
Overall, public power accounts for about 16% of all kilowatt-hour sales to retail electricity consumers. Approximately 46% of the megawatt hours of electricity produced by public power systems are generated using coal and more than 17% of MWH are generated using natural gas. This percentage of gas generation is growing since best practices for system stability dictate that the new intermittent resource capacity, such as wind and solar power be backed up at a 1:1 ratio by natural gas (mostly new Natural Gas Combined Cycle). In 2008, **27.7% of APPA member electric generating capacity (in Megawatts) and 46.4% of generation (in Megawatt-hours) was coal based. Less than 90% meet the SBREFA threshold.** Figure 1 presents the national generation portfolio from public power for 2009.

Organization of these comments

These comments are structured in the following manner:

- An introduction and executive summary
- Comments related to the requirements of Clean Air Act Section 112
- Comments related to the requirements of the Unfunded Mandates Reform Act (UMRA), the Small Business Regulatory Fairness Act (SBREFA), Executive Order 13563, and Executive Order 13132
- Comments related to general policy considerations
- Comments related to Clean Air Act Section 111
- Detailed general comments
- Detailed technical comments
- Appendices

Figure 1



Public Power MWHs by Energy Source - National 2009 fig. 1

Introduction/Executive Summary

Essential Corrections to EGU MACT Rule:

1) U. S. EPA should re-propose the rule and the final EGU MACT should not include acid gases or PM regulatory controls.
2) Public power utilities need more time for compliance for planning, public hearings, financing, procurement and construction so the U. S. EPA and the President should grant extensions.
3) U. S. EPA should provide more flexibility including subcategories for public power, electric co-ops, IOUs and merchant power.

   These subcategories include:
   - ≤100 MW for all types of utilities
   - ≤30% capacity factor peaking units (limited use – mostly for renewables)
   - NERC Reliability Standard CIP 002-4 units
   - By fuel type
   - Those utilities with physical space constraints

- APPA requested an extension to the comment period deadline and appreciated that the U. S. EPA granted that extension of one month to the comment period.

- In the rule preamble and the supporting technical documents, the U. S. EPA fails to provide any evidence of any risk to the general population from non-mercury metal HAPs and acid gases. APPA believes that it is appropriate to develop regulations under Section 112 for only the two hazardous air pollutants (mercury and nickel) for which EPA has provided evidence of a significant risk to the public. If EPA believes that non mercury metals and acid gases must be regulated, EPA should regulate these HAPs under a less onerous health-based standard. APPA believes that this action would be consistent with the call for control of hazardous air pollutants only where the U. S. EPA has determined there to be human health concerns. EPA's own study showed health concerns for only **mercury** (coal-fired generation) and **nickel** (oil-fired generation).

- APPA does not believe it unreasonable that the U. S. EPA should use its discretion to minimize the cost impact of this rule while still providing for the protection of public health. APPA believes that EPA should use its discretion in light of Executive Order 13563 (regulatory directive to minimize costs) to modify the proposed rule with a number of changes.

- U. S. EPA should <u>eliminate</u> the use of a "Franken" Plant approach to establish a MACT standard for coal and oil-fired EGUs. Specifically, APPA believes that EPA should establish a MACT that is based on the actual performance of individual EGUs for all HAPs to be regulated. <u>This change in the final rule would result in less compliance cost with little to no change in health benefits or impacts</u>.

- The proposed NSPS for SO_2, PM, and NO_x are, in practice, <u>NOT</u> achievable.

- APPA believes that the U. S. EPA should regulate mercury emissions from power production as necessary to reduce methyl mercury bioaccumulation in fish via air deposition. However, the U. S. EPA should regulate mercury from EGU's considering the comments herein, on matters such as subcategories, compliance schedules, and other factors. APPA does not presume that these reductions of mercury will affect any mercury transported from international sources of mercury including Asia and Mexico.

- U. S. EPA should not expand the proposed utility toxic rule beyond mercury and nickel since in the preamble for the proposed rule EPA provided no data as to any health risks associated with non-mercury metal HAPS and acid gases related to fossil fuel-fired EGUs. Regulating these emissions would serve no purpose and would add cost without commensurate health benefits. In addition, EPA has not shown that the regulation of acid gases (HCl, etc.) and other air toxics is necessary and appropriate.

- In assessing costs to consumers, U. S. EPA should analyze the impact of the rule in wholesale electricity markets run by regional transmission organizations, particularly in forward capacity markets.

- U. S. EPA should subcategorize and provide for the use of Generally Available Control Technology(s) (GACT) and management practices for area source utilities. U. S. EPA should also make GACT along with alternative work practice or operational standards available for municipal utilities and utilities that are physically constrained, such as those retrofitting with baghouses and scrubbers where the space needed to accommodate the addition of pollution controls is not adequate. APPA believes that the subcategory should address fuel types, combustion processes, such as circulating fluidized boilers or pulverized over air-fired boilers, physical constraints limiting the footprint of plants, and age of plants. **APPA strongly endorses the ≤ 100 MW sub-category.** This ≤100 MW subcategory should apply to <u>all</u> in the utility sector. See Appendix A

- U. S. EPA has grossly overestimated the health benefits of controlling Particulate Matter (PM) and should not consider these benefits since PM is to be controlled under the National Ambient Air Quality Standards (NAAQS) section of the Clean Air Act.

- U. S. EPA should use its discretion to regulate utility air toxics with a health-based emission standard, which would decrease costs without jeopardizing public health and safety.

- U. S. EPA should 1) enable the power sector, particularly public power utilities, to have additional compliance time beyond the standard three years in the Clean Air Act. 2) The U. S. EPA should provide extensions of one or two years each (as needed) as allowed under Presidential extension provisions (the Presidential extension should be delegated to the Governor of each state if the U. S. President desires). An extension is necessary to allow installation of pollution control equipment given time needed for planning compliance, timing and process for obtaining financing for either pollution controls (scrubbers, baghouses, etc.) for EGU MACT/NSPS final rule **or** more time is needed for fuel switching to natural gas where the natural gas pipeline development and expansion projects must be financed, permitted and built by third parties to supply the utility plants that would use the natural gas.

  APPA does <u>not</u> assert that any additional time is needed to purchase or install the combined cycle gas turbines themselves as that technology is fully commercially demonstrated, available, and even available in international markets. However, even fuel switching or conversion from coal-fired to natural gas may require permitting, financing and building of natural gas pipeline extensions, as well as natural gas storage permitting and construction. This is particularly true if a public power authority does not have power of eminent domain.

For *some* pipelines and local distribution companies (LDCs), FERC and Public Utility Commissions (PUCs) may need to change standards that would harmonize the "electric day" and "natural gas" scheduling day.

- APPA strongly recommends the U. S. EPA's final EGU MACT rules include a Title V method to accommodate any utility that cannot meet the EGU MACT compliance deadline. This administrative noncompliance procedure is already established under the Clean Air Act. This will allow for compliance time and avoid criminal and civil liability while reducing the administrative burdens on U. S. EPA and any state agencies with delegated authorities, and reduce costs and burdens on small towns with public power electric utilities.

Comments related to the requirements of Clean Air Act Section 112

Section 112 and subsequent court decisions have led to a process for establishing HAP standards that includes establishing a "floor" requirement reflecting the performance achieved in practice by the best controlled similar units, followed by an adjustment for further reductions "beyond the floor" if certain statutory criteria are met. A key element in establishing the floor is identification of appropriate subcategories within a regulated category, to ensure that the units represented by the "best performing" units are indeed "similar."

In general, the nature of many public power facilities differs from the general population of coal-fired power plants. As described in our detailed comments, public power units tend to be smaller in size, and are often space-constrained by growth in the community surrounding the generating unit since its initial construction. These limitations restrict the ability of these units to achieve the same performance levels as larger, unconstrained units, and, for those units which can comply with the proposed standards, sharply increases the cost of compliance.

We believe that the requirement that the floor represents levels "achieved in practice" is at odds with the proposed rule in at least two respects. First, the test operations and statistical treatment of the test data do not represent periods of startup, shutdown, or malfunction. Therefore those periods of operation should not be subject to the standards. A work practice approach, similar to that promulgated for industrial boiler HAPs, would be appropriate for these abnormal operating periods. Second, the continuous compliance assurance requirements – which include enforceable limits on various fuel and hardware variables like the pressure drop across a control device – are effectively more stringent than the emission standards that they support, and therefore were not "achieved in practice" by the best controlled units. Such additional levels of stringency are not authorized under the provisions of Section 112. In addition, we have a number of technical objections to the validity of determining emission compliance using these parameters. A better approach would be to exempt emissions during SSM functions or identify a much reduced set of parameters that are indicative of increased emissions, and monitor those to determine when an emission test is likely warranted.

Comments related to the requirements of the Unfunded Mandates Reform Act (UMRA), the Small Business Regulatory Enforcement and Fairness Act (SBREFA), Executive Order 13563 (Improving Regulation and Regulatory Review), and Executive Order 13132 (Federalism)

UMRA and SBREFA include provisions that require EPA to evaluate the impact of its regulations on state and local governments, and certain small entities. Most public power systems qualify under these general categories. EPA should have, but did not, engage in an adequate process of consultation with APPA or other small entities regarding these rules. Moreover, the rulemaking record shows no evidence that EPA considered substantive alternative regulatory approaches in an effort to reduce the

financial burden of these rules on state and municipal governments that own public power facilities, or that purchase power from other utilities subject to the rules. APPA believes that there are mechanisms whereby EPA could reduce this burden, while still complying with the statutory requirements of the Clean Air Act.

In addition to these statutes, two Executive Orders direct EPA, as a matter of good public policy, to minimize the economic burden of meeting environmental requirements, and to minimize the federal presence by consulting with state and local governments when developing national standards. APPA believes that EPA has failed to comply with these orders.

Additional details on these procedural cost-related requirements are included below, and in the detailed comment sections of these comments.

On of APPA's most significant concern is that the U. S. EPA has not responded to the concerns of the small business community, the U. S. Small Business Administration (SBA), and the Office of Management and Budget (OMB). The December 2, 2011 Small Entity Representatives (SER) panel discussed their concerns with the amount of time it would take to complete any emissions control installation project on a utility. The Regulatory Impact Analysis (RIA, section 10-23) includes commentary from OMB and SBA (See Appendix B). The U. S. EPA did not act upon OMB's suggestions that the EPA meet again before the rule was proposed to "gather insight on the feasibility and achievability of those limits for small entities. To the extent feasible, we recommend this meeting take place before the proposal is issued." (RIA, pg. 10-23)

APPA notes that no additional meetings were convened between December 2, 2010 and March 16, 2011 when the proposed rule was announced or by May 3, 2011 when the proposed rule was published in the Federal Register. APPA also observes that the U. S. EPA ignored the strong concerns expressed by the SER panelists regarding the three-year compliance deadline.

More than 90% of public power systems meet the definition and qualify as small businesses under the Small Business Act and the Small Business Regulatory Enforcement and Fairness Act of 1996 (SBREFA).[1]

According to EPA's Regulatory Impact Analysis (RIA), this rulemaking will affect 1,400 coal and oil-fired units with >25MW nameplate capacity units. This means approximately 200 APPA member utilities with coal-fired or oil-fired generation will need to undergo retrofit or gas conversion within 36 months. **APPA believes that the U. S. EPA grossly underestimated the costs for compliance and overall feasibility of this rulemaking on approximately 200 public power coal-fired utilities, given the compressed time.** See Appendix G or pages 20-32 of comments.

APPA believes that the U. S. EPA did not fulfill its statutorily required actions and failed to perform a full analysis under the Regulatory Flexibility Act, or "Reg Flex," and UMRA as well as SBREFA.

Since the proposed EGU Utility MACT regulations that the U. S. EPA intends to propose would almost certainly have a significant economic impact on a substantial number of small entities,[2] U. S. EPA was required, pursuant to the Regulatory Flexibility Act (RFA),[3] to convene a Small Business Advocacy Review Panel (SBAR) to thoroughly and accurately assess the impact of the proposed regulations on utilities that qualify as small businesses. During the convened SBREFA SER panel

[1] See "Regulatory Flexibility and Unfunded Mandates Reduction Act Considerations."
[2] See section titled "The Proposed NSPS Are Not Achievable"
[3] 5 U.S.C. § 601 *et seq.*,

meeting it was clear that the U. S. EPA had not adequately fulfilled its responsibilities to assess the impact of any proposed regulations since the Agency did not lay out clear and significant alternatives to the regulation that would be proposed.

The Small Business Regulatory Enforcement and Fairness Act (SBREFA) was enacted by Congress to provide small entities a meaningful voice in major federal rulemakings. Among the Act's goals are to encourage the "effective participation" of small businesses in the federal regulatory process[4] and to create a more cooperative regulatory environment among agencies and small businesses that is less punitive and more solution-oriented.[5] Section 609 of SBREFA envisions that small business panels will review "any material the agency has prepared in connection with this chapter," including information required to be part of the initial regulatory flexibility analysis.[6] A regulatory flexibility analysis typically includes descriptions of significant alternatives to the proposed rule, differing compliance or reporting requirements or timetables that take into account the resources available to small entities, and the clarification, consolidation, or simplification of compliance and reporting requirements for small entities.[7] **At the December 2, 2010 SER meeting on Utility MACT the U. S. EPA did not prepare and distribute any of these clarifications, consolidations or simplifications of the U. S. EPA regulatory options by the U. S. EPA. Subsequently, the U. S. EPA asked the SER panel participants to advise the agency and file comments a few days following this meeting. This does not follow Congress' intent for how SBREFA analysis and SBAR panels should be conducted. (**See Appendix C for letter from the U. S. Small Business Committee, June 2011, regarding similar concerns with the EPA SER process on NSPS for CO_2.)

The highly abbreviated nature of this particular small business review panel that was established for the EGU MACT rule prevented small APPA utilities from having the meaningful advisory role envisioned and outlined by SBREFA.[8] Only <u>one</u> panel meeting was provided and after that meeting, panel members were given a mere 14 days to prepare written comments on an incredibly complex topic.[9] The materials provided by EPA just prior to the only panel meeting were little more than what the EPA typically offers in a notice of proposed rulemaking. This is <u>not</u> consistent with the three prior SBREFA SER panel meetings on other proposed regulations where APPA and individual utilities were invited to participate. Those included the Clean Water Act Section 316(b) cooling water intake structures/entrainment and impingement of aquatic organisms, the ICI Boiler MACT rulemaking (<25 MW coal-fired plants) in 2003 and others held in the last ten years where the APPA has been invited to attend and participate. The SER panel meeting held on Dec. 2, 2010 was reminiscent of the very unorthodox small entity outreach undertaken by the U. S. EPA for the GHG Tailoring Rule in 2009. APPA accepted the non-SER panel approach on the GHG Tailoring Rule because of the unusual circumstances surrounding how CO_2 would be regulated. This was brought about by the cascade regulation of stationary sources of CO_2 from Section 202 of the Clean Air Act for tailpipe standards. **Alternatively, the EGU MACT regulation and the timing of that regulation required no truncated or shortened process for the SER panel. The U. S. EPA set the deadlines with the**

[4] 5 U.S.C. § 203(3).
[5] 5 U.S.C. § 203(6).
[6] 5 U.S.C. § 609(b)(4); see also 5 U.S.C. § 603(b)(3), (4) and (5) and 603(c).
[7] See 5 U.S.C. § 603(c).
[8] The presentation materials suggest that EPA was required to foreshorten the small business review process because it is under a consent decree which sets a tight schedule for the EGU MACT rulemaking. *See* Slide 8. However, the SBREFA review process is an important part of any major federal rulemaking. EPA should have factored that process into any rulemaking schedule it agreed to and defended before a federal district court judge. As a practical matter, the consent decree allows EPA to unilaterally return to the judge to request additional time to complete the EGU MACT rulemaking. If EPA feels so constrained by the consent decree that it cannot provide an adequate SBREFA review process, then it should ask the judge for a schedule extension.
[9] While providing only 14 days for written comments by panel participants, EPA nevertheless propounds six slides of questions for those entities. Many of those questions were answered by all EGUs in response to Parts 1 and 2 of the EGU MACT ICR. Others would require far more than 14 days to provide meaningful responses. If EPA is serious about wanting input on the questions it posed to panel members, then a much longer comment period should be provided.

court in response to litigation and should have factored the timing for a full and complete SBREFA panel. U. S. EPA acknowledged that it needed this time during the meeting at its offices on December 2, 2010. APPA believes that the December 2, 2010 meeting made a mockery of the productive goals of SBREFA and the SER panel process. The U. S. EPA identified no regulatory alternatives to reduce costs and ignored the recommendations offered by SER panelists, such as GACT controls for subcategories.

EPA Has Failed to Meet the Requirements of the Unfunded Mandates Reform Act of 1995 (UMRA[10]) and Executive Order 13563 and Executive Order 13132 of 1995.[11]

As stated in Executive Order 13563, and to the extent permitted by law, each agency must, among other things: (1) propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify); (2) tailor its regulations to impose the *least burden on society*, consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, *the costs of cumulative regulations*; (3) select, in *choosing among alternative regulatory approaches*, those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; *distributive impacts*; and equity); (4) to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt; and (5) identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public.

APPA acknowledges that the U. S. EPA has discretion in developing utility air toxics rules under Section 112 and believes that this discretion allows U. S. EPA to consider the economic realities facing the country today. It is noted that U. S. EPA has taken relatively little discretion in developing MACTs for virtually every industrial source **except** for electric utilities, which got entirely different treatment under (n)(1)(a). In addition, APPA believes that Executive Order 13563 provides important guidance as to the use of U. S. EPA's discretion. All the information provided by U. S. EPA in the preamble of the proposed air toxics rule indicates that the proposed rule will have a major impact on the fuel mix of electric utilities and electric generating capacity. The projected cost for the rule is significant while providing only minimal benefits from the direct reduction of hazardous air pollutants. **By U. S. EPA's own calculations, 99.99% of all benefits from the proposed rule will result from co-benefits associated with estimated reductions of SO_2 and NO_x resulting in lower ambient $PM^{2.5}$ and ozone levels. However, these co-benefits would naturally follow the implementation of other CAA requirements currently in progress, including the revised $PM^{2.5}$ and ozone NAAQS as well as the one hour SO_2 and NO_x NAAQS, which will lead to lower SO_2 and NO_x caps under the Clean Air Transport Rule (CATR now called Cross State Air Pollution Rule)**.[12]

APPA respectfully submits that the U. S. EPA has failed to meet the requirements of Unfunded Mandates Reform Act of 1995 (UMRA) and Executive Order 13132 in this rulemaking. Before proposing the MACT rule, UMRA required EPA to undertake an assessment of the impact of the rule on local government under sections 202 and 203 of the Act. 2 U.S.C.A.§§, 1532 -1533. (See Appendix D) The requirement for this assessment reflects Congress' concern regarding the

[10] 2 U.S.C.A. §§1331-1335 (2011).

[11] 64 Fed. Reg. 43255 (Aug. 10, (1999

[12] In the preamble for CATR, EPA discusses this relationship between revisions to lower a NAAQS and future reductions of SO_2 and NO_x cap under CATR.

unintentional effects of federal mandates, including federal regulations, on local governments and the spill-over effects on local communities, including the tax base of such local economies and their ability to provide other governmental services. In the context of this rule, these impacts could be especially significant. First, the cost of power in small municipalities will be driven up by the compliance costs of the proposed utility MACT, particularly if EPA does not take APPA's suggestions to reduce the regulatory burdens of complying with the proposed MACT standards. Second, because municipal power generation is a pivotal component to many local economies and in turn the ability of municipal governments to provide other community services, it is critical that EPA carefully assess the social and economic impacts of compliance costs or the consequences of the potential shut down of public power plants on municipal governments, in addition to residents and local industries served by public power. The agency's proposed action does not reflect these considerations despite the direction to do so under UMRA, SBREFA and the Executive Orders..

APPA is particularly troubled by being unable to find information in the rulemaking record regarding the qualitative and quantitative assessment of the anticipated costs and benefits of the proposed regulation on local governments. Nor did EPA's analysis extend to which costs to local governments may be paid with federal financial assistance or otherwise paid for by the Federal government, including any assessment of the disproportionate effect of the MACT rule on regions of the country. In some parts of the country there is no infrastructure to deliver sufficient additional supplies of natural gas to meet the additional demand in many states. **APPA respectfully submits that despite information in the preamble to the proposed rule, there is little information in the background documents in the record of this proposed action that EPA has in fact consulted with state and local officials "early in the process of developing the proposed action." Id. at 25086**.

APPA acknowledges that the preamble to the proposed rule states that EPA has convened a meeting of the "Big 10"[13] national organizations representing state and local elected officials, held on October 27, 2010 in Washington pursuant to UMRA. Although the EGU MACT proposed rule states that the potential impacts of the proposed rule must be disclosed and considered with the affected regulated community under UMRA's Section 204, Id. At 25085, APPA can find no record in the RIA of any of the details of the proposed rule being shared with the October 27, 2010 "Big 10" meeting. We respectfully wish to point out that APPA's examination of the technical support documents for this rulemaking has failed to yield an agenda or minutes of this meeting with the "Big 10" organizations. We also respectfully observe that it is unlikely that EPA had reached the point in its Utility MACT decision-making in October 2010 when the agency could have shared meaningful information with elected officials regarding the costs and other consequences (such as the shutdown of plants for cities and their service communities) of regulatory alternatives. Even if these assessments had been made in October 2010 (which changed to the Regulatory Impact Assessment in early May 2011 suggest are unlikely), APPA also submits that the "Big 10" organizations are unlikely to have had stakeholders that were impacted by the MACT rule and therefore EPA's statement that it has received no additional questions or requests from state or local officials concerning the rulemaking, *id at 25086,* comes of little surprise. While we have been unable to locate the list of 112 state and local governments which EPA states it provided addresses for at these meetings, we are not aware that any of these cities or their public power providers received any meaningful communications regarding potential impacts.

[13] The Big Ten organizations are defined at 76 FR 25085 (May 3, 2011) as National Governors Association, National Conference of State Legislatures, Council of State Governments, National League of Cities, US Conference of Mayors, National Association of Counties, International City/County Management Association, National Association of Towns and Townships, County Executives of America, and Environmental Council of States. Specific section: RFA/SBREFA analysis under "Consultation with Government."

Not until December 2011 did EPA actually invite public power (along with investor–owned utility) representatives to a meeting to discuss the potential regulatory impacts of the rule. In fact, APPA submits, many more communities will be negatively impacted by the costs of the proposed MACT rule, causing many municipalities to cease to provide low-cost electricity and steam to communities and industries that they currently service.

Section 202 of UMRA requires statements to accompany proposals of significant regulatory actions, defined as ones that in the aggregate may result in the expenditure by state, local, and tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more (adjusted annually for inflation) in any one year, and before promulgating any final rule for which a general notice of proposed rulemaking was published, the agency shall prepare a written statement containing—

(1) an identification of the provision of federal law under which the rule is being promulgated;
(2) a qualitative and quantitative assessment of the anticipated costs and benefits of the federal mandate, including the costs and benefits to state, local, and tribal governments or the private sector, as well as the effect of the federal mandate on health, safety, and the natural environment and such an assessment shall include—
  (A) an analysis of the extent to which such costs to state, local, and tribal governments may be paid with federal financial assistance (or otherwise paid for by the federal government); and
  (B) the extent to which there are available federal resources to carry out the intergovernmental mandate;

(3) estimates by the agency, if and to the extent that the agency determines that accurate estimates are reasonably feasible, of—
  (A) the future compliance costs of the federal mandate; and
  (B) any disproportionate budgetary effects of the federal mandate upon any particular regions of the nation or particular state, local, or tribal governments, urban or rural or other types of communities, or particular segments of the private sector;

(4) estimates by the agency of the effect on the national economy, such as the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of United States goods and services, if and to the extent that the agency in its sole discretion determines that accurate estimates are reasonably feasible and that such effect is relevant and material;

(5) a description of the extent of the agency's prior consultation with elected representatives (under section 204) of the affected state, local, and tribal governments;

(6) a summary of the comments and concerns that were presented by state, local, or tribal governments either orally or in writing to the agency; and

(7) a summary of the agency's evaluation of those comments and concerns.

Section 203 requires that before establishing any regulatory requirements that might significantly or uniquely affect small governments, agencies shall have developed a plan under which the agency shall—

(1) provide notice of the requirements to potentially affected small governments, if any;

(2) enable officials of affected small governments to provide meaningful and timely input in the development of regulatory proposals containing significant federal intergovernmental mandates; and
(3) inform, educate, and advise small governments on compliance with the requirements.

EPA's Poorly Managed SBREFA SER Panel

At the December 2, 2010 EGU MACT meeting the U. S. EPA materials did not include any possible rulemaking alternatives or any information about possible compliance or reporting options. Moreover, the material lacked any results of EPA's analyses of the data from the extensive information collection request (ICR) that EPA identified as being "critical to the promulgation of an EGU MACT rule." **APPA urged that additional small business SER panel meetings be held following a better staff review of the data, and that small entities be given the opportunity to comment on real regulatory alternatives once the U. S. EPA identified options. APPA would have been pleased to participate in that more thorough process**.[14] See Appendix E for a copy of the APPA comments in response to the EGU MACT SER meeting.

APPA believes EPA should have fully assessed the potential impacts of agency rules on small entities, including through solicitation and review of comments from small entities and examination of regulatory alternatives that achieve the same purpose(s) of the rule while minimizing impacts to small entities.[15] In addition, RFA requires federal agencies to prepare and publish an initial regulatory flexibility analysis, and to perform a final regulatory flexibility analysis when proposing a regulation that would have a significant economic impact on a substantial number of small entities. It is clear that the proposed Utility or EGU MACT rule will have a significant impact on a substantial number of small entities especially if the EPA considers the number of smaller public power utilities. Approximately 10% of governmental or public power utilities will be directly impacted by this rulemaking (200 out of 2000) and the likely impact is projected at much greater than 5% of utility revenues. All public power utilities will be impacted by significantly increased wholesale electricity prices.[16]

Specifically, APPA is very disturbed that some of the recommendations made by the SER participants at the December 2011 SER panel meeting (and later in writing) were ignored and not even offered in the rulemaking. For example, the EPA did not discuss subcategorizing by age, type of plant, fuel, physical space constraints or useful anticipated life of the plant. Nor did the U. S. EPA provide any opportunity for smaller emitters to use GACT—often used in other U. S. EPA MACT regulations to alleviate the regulatory costs and operational difficulties that would have burdened other small businesses including dry cleaners, metal fabricating, metal finishing, and others. It is in that context that APPA asks and will continue to ask for both the U. S. EPA and OMB to consider these APPA comments under SBREFA during inter-agency review of the final rule.

Since all APPA member public power utilities are not-for-profit, APPA also requests that APPA comments on the EGU MACT be considered in the context of the Unfunded Mandates Reform Act (UMRA). In particular, it should be noted that all additional regulatory permitting costs would be incurred by public power utilities. **Accordingly, APPA asks that comments on the Utility MACT submitted by municipal or state governments (including their electric utilities) also be considered under SBREFA and UMRA.**

[14] For more specific information please see APPA's general comments on the December 2, 2010 SBREFA SER
[15] *See* 5 U.S.C. § 601 *et seq.*; *see also* Pub. L. No. 96-354, § 2(a), 94 Stat. 1164 (1980).
[16] See page 45 under APPA's General Comments number 13.

APPA's members who operate power plants that burn coal, particularly in the Midwestern and Southeastern parts of the country will face the biggest impact under the EGU MACT/NSPS rule. In addition to the impacts a proposed rule would have on those APPA power producers that generate their own electricity using coal, other APPA members who purchase electricity from the open market generated from coal – or where coal generation keeps the market clearing price lower - would face significantly higher costs for power, which, in turn, would be passed on to the residential consumers and businesses of the communities they serve.

EPA must also understand that any adverse cost impacts from the EGU MACT would extend directly to municipal and local government operating budgets during a very difficult economic time. APPA members are not-for-profit entities, and as such serve no shareholders. Increasing operating costs on these power producers would be passed on directly to rate payers. Significantly increased costs may also cause reduced Payments in Lieu of Taxes (PILOT) from APPA members to municipal government general funds. PILOT payments are an important part of many municipal operating budgets. Smaller PILOT payments to general municipal budgets would likely result in cuts to essential governmental services, including fire, police, schools and EMT personnel. This could not come at a worse time, as municipal governments are seeking even larger contributions from the public power electric utilities they govern to help fend off other dramatic short-falls in municipal budgets for essential governmental services**. In 2009, over 66% of surveyed municipalities were engaging in hiring freezes or layoffs due to economic conditions.**[17] The proposed MACT regulations will create significant economic impacts for many utilities, causing further significant municipal budget shortages, and could force further layoffs and furloughs. This downward cycle would only deepen the financial stress felt in local economies. Although we do not have 2010 figures from our municipal membership, APPA notes that many cities have seen continued loss in tax revenue and property taxes in 2011.

APPA is concerned about the ability of small entities or nonprofit utilities such as those owned and/or operated by rural electric co-op utilities, and municipal utilities to comply with the proposed standards within three years. EPA identified a variety of small entities that will have to comply with the new rule, many of which will face substantial compliance costs.[18] In the proposal, EPA states that 102 of the estimated 1,400 EGUs are owned by 83 small entities. EPA further estimates that 59 of the identified entities will have annualized costs greater than one percent of their revenues. APPA believes that U. S. EPA has not fully recognized the number of small entities that are impacted by this rule. **This poor analysis reflects both a poor analytical preparation for the rulemaking and a disregard of what the EPA was told during the U. S. EPA SBREFA SER panel meeting on December 2, 2010**. The SER panelists explained in December 2010 that under these current economic conditions they have constraints on their ability to raise capital for the construction of control projects and to acquire the necessary resources in order to meet a three-year compliance deadline.

In the proposed rule, EPA identified a number of mechanisms - such as work practice standards, sub-categorization, health based compliance options, and emissions averaging - that it explains will lessen the burden on small businesses. While these actions may reduce the burden to a limited degree, they will be far from enough to make the final rule cost effective for many small and medium sized public power utilities. APPA believes that the ultimate impact on many of these entities will be enormous. They are certainly "significant" within the meaning of the Regulatory Flexibility Act (RFA). The monetary impact on small businesses will be substantial enough to strain their financial well being. The present sluggish economy simply does not provide the financial resources for many of these small utilities to take on the additional costs of retrofits to meet the proposed MACT standards in

[17] Hoene, Christopher W., "City Budget Shortfalls and Responses: Projections for 2012," National League of Cities, 2009
[18] *See 76 FR 25083*

three years. More time and more flexibility are needed for public power utilities. (See section on timing, page 22)

The EPA should acknowledge that the price of compliance increases as size of generating unit decreases.[19] This means that smaller generating units will be impacted more in their decision to comply with EPA's toxics rule. This disproportionately large impact poses a much more serious compliance hurdle for small communities that depend on coal fired generation to meet their base load demand. Coal plant emissions control retrofits to reduce SO_2 emissions cost on average three times as much when installed on smaller generating units. In addition, by using EPRI data it can be seen that **the price of compliance <u>doubles</u> for NO_x control equipment as the size of the unit is decreased from 100 MW to 50 MW. APPA believes that the U. S. EPA did not adequately consider the disproportionately large cost of compliance on small communities**.[20]

Though the utility industry may be able to produce and install the technology necessary to upgrade coal plants, smaller plants that represent smaller electricity sales and those that exist on the margin will be incrementally charged more by vendors and contractors. Just as home buyers looking for home repair or modification during the housing bubble paid a large time-dependent scarcity price on labor, public power utilities will face similar costs. Less desirable compliance projects at smaller generating units will likely be bid in at prices that reflect the lower desire to capture those projects or the opportunity cost of lower performance on a larger job. Smaller plants that already have to pay three times more for controls equipment will also have to pay more for labor.

The cost to comply with this proposed rule for a small power plant (approximately 50 MW in size) is equivalent to purchasing a new gas-fired power plant. In effect, by not subcategorizing to consider the disproportionately high cost on small communities the EPA is dictating a fuel switch. See the section on page 17 regarding the details of subcategorizing units ≤ 100 MW. This subcategory will greatly help the public power and broader utility industry.

EPA has Underestimated the Impacts of the Proposed Rule on Smaller Utilities Despite SER Panel

U. S. EPA identified a variety of small entities that will have to comply with the new rule, many of which will face substantial compliance costs. *See 76 FR 25083.* One way U. S. EPA defined a small entity was an electric utility that generated four million megawatt-hours of electricity per year or less. In the proposal, U. S. EPA states that 102 of the estimated 1,400 EGUs are owned by one of 83 small entities. U. S. EPA further estimates that 59 of the identified entities will have annualized costs greater than one percent of their revenues. **APPA believes that the U. S. EPA has not fully recognized the number of small entities that are impacted by this rule.** This is a critical failing because many of these entities have severe constraints on their ability to raise capital for the construction of control projects, and to acquire the necessary resources in order to meet a three-year compliance deadline. This financial strain is mostly caused by the inclusion of acid gas controls and PM controls that greatly increase the cost of this regulation and require more retrofit time. The U. S. EPA should re-propose the rule to address only mercury (coal-fired) and nickel (oil-fired) limits with subcategories – especially the ≤ 100 MW subcategory discussed in detail Appendix A.

APPA notes that the U. S. EPA's Regulatory Impact Analysis (RIA) states that the U. S. Small Business Administration (and presumably OMB) expressed concerns that the U. S. EPA failed to identify and offer as regulatory alternatives a number of options on the proposed EGU MACT rule before it was proposed. A Small Entity Representative (SER) panel was convened on Dec, 2, 2010 and no regulatory options or regulatory alternatives were provided as required under the Small

[19] Bernstein analysis report

[20] U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?, BernsteinResearch, 2010

Business Regulatory Enforcement and Fairness Act (SBREFA). Instead the SER panelists gave both verbal recommendations and followed up with written recommendations ten days later that identified regulatory options to reduce costs while meeting the requirements of the law to reduce mercury. None of those recommendations for subcategories (by size, by fuel type, by generation technology type or by geographic isolation (rural)) were even proposed by the EPA in the proposed rule. The EPA's proposed rule did not explain why none of these recommendations were considered and not used. That explanation is required under SBREFA and Unfunded Mandates Reform Act (UMRA) and both of these statutes deal with regulatory decisions for local government-owned utilities. APPA has discussed a small unit subcategory related to space constraints since 2004 so this should not be a new idea to the U.S. EPA staff. APPA has provided many aerial photos showing space constraints. (See Appendix F for APPA's comments.)

The OMB and SBA also commented (captured in the RIA, Section 10, pp. 10-27) that the U. S. EPA should have convened a panel with regulatory alternatives offered to the SER panelists and that, at a minimum before the proposed rule was published, a second meeting should have been held where these regulatory options should have been discussed. Additionally, SBA asked for the EPA to consider granting an additional year to the smaller utilities that would need to procure, contract, construct, install, and calibrate control technologies to meet the EGU MACT requirements since these units are often baseload units with inadequate backup generation to support the municipal utility during the scheduled outages. The proposed rule did not mention any plans to offer an additional year to these smaller entities and was dismissive of the serious reliability issues for smaller communities (especially in the Midwest) where many of the retrofits or conversions to natural gas will take place within three years of the final rule.

APPA urges U. S. EPA's final EGU MACT rule to contain ≤100 MW subcategory to minimize impacts to smaller units

APPA points out that this recommended subcategory, primarily designed for public power utilities ≤100 MW would help minimize uneconomical plants from facing retirements. Further this subcategory, while still reducing mercury through GACT controls, would provide "wiggle room" during the time of transition to ensure system or regional reliability—particularly in the Midwest where these <100 MW units are more common. APPA believes that this <100 MW subcategory should also be provided for investor utilities, merchant power or electric-co-operative utilities although APPA notes that 106 of these units are in public power communities. While the subcategory would help a handful of investor or electric co-operative utilities, it would most benefit local governmental utilities. Of the <100 MW utilities across the U. S. the total generating capacity affected, if a subcategory is created, is only 5%. Thus this subcategory is not a "loophole" and should not concern the U. S. EPA or public health officials. See Table1 for details.

Note: Rounding up of emission limits was practiced by EPA for the proposed EGU MACT Rule.

Table 1	**EGU MACT Range of 99% CI Upper Predicted Limit (UPL) Values from RMB Small Unit Subcategorization Analysis Applying Student T Test Methodology.**				
	EPA Proposed Emission Standards		RMB Estimates of Emissions Standards "Full 12%" of Coal Units ≥ 8300 Btu/Lb With Small Unit Subcategory		
	Pounds per Million Btus		lbs./mmBtu	lbs./mmBtu	lbs./mmBtu
HAP	< 8300 Btu/lb (lignite)	≥ 8300 Btu/lb	≤ 100 MWs	> 100 MWs	All Units
Mercury	4.0 E-6	1.2 E-6	2.3E-06	2.1E-06	2.1E-06
			EPA's approach for using the lowest reported ICR value for a unit was applied in these calculations. RMB sensitivity analysis also considered use of average reported unit emissions and the statistical methods EPA applied for industrial boiler MACT estimates. Doing so increases emission standards relative to this table.		
Total PM (as surrogate for metals)	Same as > 8,300 Btu/lb	0.030	0.060	0.020	0.030
Filterable PM	NA	NA	0.020	0.010	0.010
Total Metal HAPS	Same as > 8,300 Btu/lb	0.000040	0.000110	0.000040	0.000040
HCl	Same as > 8,300 Btu/lb	0.0020	0.0230	0.0020	0.0020
SO2 (FGD/DSI Only)	Same as > 8,300 Btu/lb	0.2	0.2	0.2	0.2
Organics (Work Practice Standard)	Same as > 8,300 Btu/lb	Boiler Tune-Up Every 18 Months	Boiler Tune-Up Every 18 Months	Boiler Tune-Up Every 18 Months	Boiler Tune-Up Every 18 Months
# of Coal Units	30	1061	294	767	1061
# in EPA ICR Reporting Mercury Emissions	11	328	91	237	328
Number in Mercury HAP Best Performing 12% Calculation	2 (Hg Limit based on "Beyond the Floor" analysis)	40	35	92	127
Number in Non-Mercury HAP Best Performing 12% Calculation	2 (Hg Limit is based on "Beyond the Floor" analysis)"	127	35	92	127

Color Code:	
No color	No change in Estimated Emissions Standard
Yellow	Increased value
Orange	Decreased Value

EPA's own Regulatory Impact Analysis and economic analysis says that 97 municipal or state utilities will have a compliance cost of $666.3 million in annual direct compliance costs (RIA, 10-30). This EPA cost analysis does not factor other costs such as:

(a) Cost of purchasing power off the market or from other municipal utilities during scheduled outages for retrofit.

(b) Costs for fuel switching to natural gas.

(c) Inability to sell coal ash or coal combustion residuals (CCR) to the cement industry due to the sodium levels from Dry Sorbent Injection (DSI) exceeding the cement industry's ASTM (formally known as American Society for Testing and Materials)[21] standards for sodium content. These coal ash residual costs resulting from the DSI technology were not mentioned or considered in the proposed rule's economic analysis.[22]

As with all EPA regulations, the costs to the ultimate consumer of the U. S. EPA regulation of CCR as hazardous were not considered. This is most unfortunate since small businesses are often price sensitive to fluctuations in energy pricing. While the CCR rulemaking has not been finalized, APPA points out that, if coal ash is designated as hazardous waste under RCRA (Subtitle C), state and municipal governments might feel compelled to remove and remediate the coal ash fill from under buildings, at landfills, and under existing highways and roads. These coal ash/CCR costs were not considered in this rulemaking, but there is certainly a link between these two proposed rules. There is no mention of this very significant impact of this proposed rule in the RIA, given the lost revenue and increased utility costs associated with coal ash being not useful for the commercial market due to its very high sodium content. The EPA's press announcements and all subsequent presentations given to the utility sector mention that they have considered the allegations of the "train wreck" and that they have considered the convergence of many EPA regulations on the utility sector in a short timeframe. Clearly the EPA did not do a thorough job looking at the costs of these regulations but chose to point out only the costs of the EGU MACT without any consideration of the effect of DSI controls on the ability to sell or trade coal ash.

For municipal electric utilities, a RCRA hazardous waste Subtitle C designation - or simply making the ash undesirable to the cement industry (due to sodium content from DSI technology) - would often mean a dramatic increase in the cost of disposal. These increased coal ash disposal costs can range between 5% and 24% of a municipal government's utility budget (when considering larger public power utilities that exceed the SBREFA threshold). The typical cost range is between 2% and 14% depending upon proximity to a hazardous waste landfill (Source: APPA's comments to the U. S. EPA on coal ash, Nov. 2010). Impacts referenced in Table 3 on page 75.

APPA notes that there may be unintended cost consequences to eastern coal varieties because utilities using eastern coal variety's coal may not be able to meet the EGU MACT/NSPS proposed rule. APPA notes that use of western coals by the remaining coal fired power plants may well cause utilities of all sizes to be more reliant upon rail transportation due to moving more western coal to more power plants. As captive customers of rail companies, power plants would pay significantly more for delivery of western coals. The displacement of the eastern coal, cost and the related transportation impacts were not considered by the U. S. EPA. The costs of transportation of coal are

[21] http://www.astm.org/ABOUT/overview.html

[22] An APPA member noted that if they were to start using DSI at their generating station they estimate that it would cost an additional $100 million over 20 years to dispose of the fly ash (This includes the revenue loss from selling it, increased material handling costs, the need to build additional landfill cells and all the operating and closure costs associated with the landfill). These numbers assume that fly ash will not be declared a hazardous waste.

almost always more expensive than the cost of the coal itself. If the U. S. EPA's final EGU MACT/NSPS rulemaking causes more fuel switching from eastern to western coals, the additional transportation costs (and captive rail cost concerns) may well be another major factor not considered in the U. S. EPA Regulatory Impact Analysis (RIA). This is yet another reason why the U. S. EPA's failure to subcategorize between eastern and western coal represents a serious technical flaw which is unlikely to survive judicial challenge.

While some larger public power utilities may not have as many logistical challenges as the smaller municipal systems, APPA notes that it is unwise to have so many utilities (regardless of size) attempting to retrofit and convert over the same three-year period. Additionally, the U. S. EPA failed to avail itself of its ability to use GACT controls and subcategorize adequately (especially for ≤ 100 MW units) to help either the smaller utilities or the larger utilities. GACT controls have been used successfully in many other EPA MACT rules, including the following industries:

- Iron & Steel Foundries
- Electric Arc Steelmaking
- Coatings Operations Area Source Controls Rule
- Clay Ceramics Manufacturing
- Glass Manufacturing
- Secondary Nonferrous Metals Manufacturing
- Paint Stripping & Miscellaneous

Timing for Compliance Requires 77 Months for Public Power Utilities due to Governance Requirements and Financing of Projects

The U. S. EPA has on several occasions made compliance extensions applicable to an entire industry or subcategory.[23] The analysis presented below focuses on these provisions and why in particular public power facilities face unique additional municipal and state laws that make it urgent for EPA to utilize its authority to provide compliance extensions for the industry. First we provide a general discussion of the Agency's authority to provide compliance extensions. Then we describe assumptions that the Agency states in the preamble about the industry's ability to comply with the proposed standards and why we believe that they are in error. Third, we describes the results of an independent APPA-commissioned survey[24] of the public power industry and the types of problems that members will have in complying with the standards if EPA fails to take the recommended actions to reduce the regulatory burdens of complying with the proposed MACT standards. We urge EPA to pay particular attention to municipal and state law affecting bidding procedures for equipment design, fabrication and labor and the state and municipal laws that affect the timing and procedures for public referendums for issuance of public bonds, eminent domain concerns and other unique issues such as easements, high density zoning and union labor that municipalities have reported will necessarily delay compliance with final emission standards for up to six years after they are promulgated. On this basis APPA urges U. S. EPA to grant a one-year state compliance extension in the final rule. We also suggest that it is critical for U. S. EPA to consider the provision in the Clean Air Act that enables the President to grant extensions for up to two additional two-year periods and the source-by-source showings that governors and mayors should provide to be eligible for such extensions from compliance.

[23] National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fred Electric Utility Steam Generating Units, proposed rule, 76FR24976, May 3, 2011.
[24] See survey summary in Appendix G

Statutory and regulatory provisions

The Clean Air Act addresses compliance schedule requirements in Section 112(i)(3) and (4), as set forth below:

§112(i)(3) Compliance schedule for existing sources
(A) After the effective date of any emissions standard, limitation or regulation promulgated under this section and applicable to a source, no person may operate such source in violation of such standard, limitation or regulation except, in the case of an existing source, the Administrator shall establish a compliance date or dates for each category or subcategory of existing sources, which shall provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard, except as provided in subparagraph (B) and paragraphs (4) through (8).

(B) The Administrator (or a State with a program approved under subchapter V of this chapter) may issue a permit that grants an extension permitting an existing source up to 1 additional year to comply with standards under subsection (d) of this section if such additional period is necessary for the installation of controls. An additional extension of up to 3 years may be added for mining waste operations, if the 4-year compliance time is insufficient to dry and cover mining waste in order to reduce emissions of any pollutant listed under subsection (b) of this section.

(4) Presidential exemption [25]- The President may exempt any stationary source from compliance with any standard or limitation under this section for a period of not more than 2 years if the President determines that the technology to implement such standard is not available and that it is in the national security interests of the United States to do so. An exemption under this paragraph may be extended for 1 or more additional periods, each period not to exceed 2 years. The President shall report to Congress with respect to each exemption (or extension thereof) made under this paragraph.

Proposed section 63.9984 of the HAP rule states that "*if you have an existing EGU* [electric generating unit], *you must comply with this subpart no later than [3 years after date the final rule is published in the* ***federal register****]*."[26] Pursuant to a Consent Decree, the U. S. EPA Administrator must sign a final rule by November 16, 2011.[27] The recently promulgated HAP rule for industrial boilers was signed by the U. S. EPA Administrator on February 21, 2011,[28] but was not published in the Federal Register (making it effective) until March 21, 2011. It specified a compliance date for existing units of March 21, 2014 (three years after publication).[29] Assuming a similar one-month lag for publication of the Utility HAP rule would suggest a three-year compliance interval would result in a compliance deadline of December 16, 2014. For any unit granted a one-year extension under §112(i)(3)(B), the compliance date would be December 16, 2015. Hence, a source can be assured that it has **37 months** following issuance of the final rule to comply, and that it may be able to obtain an additional 12 months (*49 month total*), <u>but approval of the 49 month alternative is at the discretion of the permitting authority.</u>

[25] APPA points out that the CAA's statutory term "exemption" in this context does **not** mean a complete exemption from the rule meaning no installation of pollution controls. A "Presidential exemption" in the context of these comments functions as a regulatory compliance <u>time extension</u>. See CAA 112(i)(4). APPA's recommendation for the use of the Presidential exemption is really a request for additional time.
[26] Ibid., p.25102.
[27] Consent Decree, American Nurses Association, et. al., v. USEPA, Civ. No. 1:08-cv-02198 (RMC), US District Court for the District of Columbia, http://www.epa.gov/ttn/atw/utility/consentfnl.pdf .
[28] <u>National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters</u>, USEPA, 76FR15662.
[29] Ibid., 76FR15665.

U. S. EPA provided limited discussion of the compliance schedule requirements in the preamble of the proposed rule. [30] U. S. EPA stated, "*We believe that 3 years for compliance is necessary to allow adequate time to design, install and test control systems that will be retrofitted onto existing EGUs, as well as obtain permits for the use of add-on controls. We believe that the requirements of the proposed rule can be met without adversely impacting electric reliability. Our analysis shows that the expected number of retirements is less than many have predicted and that these can be managed effectively with existing tools and processes for ensuring continued grid reliability. Further, the industry has adequate resources to install the necessary controls and develop the modest new capacity required within the compliance schedule provided for in the CAA. … EPA believes that the ability of permitting authorities to provide an additional 1 year beyond the 3-year compliance time-frame as specified in CAA section 112, along with other compliance tools, ensures that the emission reductions and health benefits required by the CAA can be achieved while safeguarding completely against any risk of adverse impacts on electricity system reliability. "* The ensuing discussion explained that U. S. EPA believes that many of the units requiring retrofit technology for acid gases can use dry sorbent injection (DSI) technology, which requires less time to install than the dominant approach currently used by electric utilities (flue gas desulfurization, or FGD), but that even if FGD systems were chosen by utilities, they could be "*installed within the 3-year window*." For non-mercury metal HAPs, "*EPA has assumed that companies with ESPs will likely upgrade them to FFs*." And for mercury, EPA assumed that compliance would come through the combined contribution of non-mercury specific controls like FGD and FFs, and activated carbon injection systems (ACI). EPA noted that some facilities would have multiple retrofits, requiring a staggered installation sequence, but even these could be accommodated within the four year schedule.

U. S. EPA considered the possibility that widespread retirement of existing coal units and replacement with new capacity could strain industry construction capabilities, but concluded that "*very little new capacity*" would be needed to maintain adequate electricity reserve margins, and "*EPA projects that approximately 9.9 GW of coal-fired generation (roughly 3 percent of all coal-fired capacity and 1% of total generation capacity in 2015) may be removed from operation by 2015*."

U. S. EPA's assessment of timing appears to reflect immediate action based on the proposed rule (versus waiting until a final rule is promulgated). "*EPA expects that sources will begin promptly, based upon this proposed rule, to evaluate, select, and plan to implement, source-specific compliance options.*" U. S. EPA also believes that Regional Transmission Organizations (RTOs) should get started on the new regulations and states, "The RTOs/ISOs also have a very important role to play and it appears that a number of them are already engaged in preparing for these rules." The Agency cites two presentations as evidence of this early action: a presentation by the PJM Interconnection,[31] and a second by MISO.[32]

U. S. EPA notes that it is developing a number of regulations impacting the power sector in addition to the proposed HAP rule. These regulations include the interstate transport rule (and its multiple iterations as U. S. EPA modifies ambient air quality standards), the coal combustion waste rule, the cooling water intake structure rule, and limits on greenhouse gases from both new and existing power plants. Although U. S. EPA does not address the planning difficulty this poses for the regulated utilities, it does observe that U. S. EPA's job will become easier over time as "*the Agency will have an opportunity to take into account the effects of the earlier rulemakings in making decisions regarding potential GHG standards for EGUs*."

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[30] Op. Cit., National Emission Standards, 76FR25054 - 25058.

[31] Consideration of Forthcoming Environmental Rules for Resource Adequacy in PJM, presentation to Harvard Electricity Policy Group, December 9, 2010, Tucson, AZ, Paul Sotkiewicz, Chief Economist, PJM Interconnection.

[32] Proposed EPA Regulation Impact Analysis, MISO Planning Advisory Committee, November 23, 2010, https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2010/20101123/20101123%20PAC%20Item%2002%20Proposed%20EPA%20Regulation%20Impact%20Analysis.pdf .

In addition to the foregoing discussion in the preamble to the proposed regulation, U. S. EPA conducted an analysis of the feasibility of the retrofit program required by the proposal.[33] The conclusion of this analysis was: "… *a reasonable, moderately paced effort of the power sector and supporting industry, including some early starts, would result in many of the needed retrofits being installed by January 2015 with some needing up to an additional year. In order for all retrofits to be completed by January 2015, most projects would have to start early and the sector would have to engage in a more aggressive deployment program."* The analysis drew from U. S. EPA's modeling of compliance measures. A key conclusion from that modeling was the projected widespread use of DSI technology instead of FGD, with a resource savings of 80-90% based on the simpler DSI systems. Additionally, the feasibility analysis implies that the capital cost assumed for fabric filter (FF) systems, the most broadly deployed compliance system in U. S. EPA's analysis, was about 30% the amount of a similarly sized wet-FGD. EPA also assumed that the most resource-intensive compliance option was retirement of an existing coal unit with replacement by a new coal unit, which U. S. EPA assumed would cost about 5 times the amount of a wet-FGD retrofit. These cost assumptions were critical to U. S. EPA's resource and timing analysis because the U. S. EPA assessment of industry's capacity to design, manufacture, and install compliance hardware was based on the capital cost of compliance measures. U. S. EPA also based its expectations for feasibility in part on improving past schedules for installing air pollution control (APC) systems, and stated, "*EPA believes that almost all future APC retrofits can be completed far more quickly than were historical APC projects*." **The U. S. EPA feasibility analysis for the HAP rule did not consider any of the resource requirements for compliance with the other regulations U. S. EPA cited in its preamble.**

In summary, U. S. EPA predicts very little problem in meeting the three-year compliance schedule proposed in the regulation, if the additional year of compliance time is provided to "some" units. The key assumptions supporting this conclusion are:

- The use of low-cost, simple, DSI systems to control acid gases, instead of more complex FGD systems
- Faster retrofits than similar projects in the past
- Compliance requirements of other regulations have no impact on HAP compliance
- The small number of projected retirements, about 10 GW of coal capacity
- Early planning action by regulated utilities
- Early planning action by RTOs

General compliance timing issues

Each of the key assumptions in EPA's analysis of compliance timing merits consideration.

<u>DSI systems</u>

DSI systems have been used by some utilities to address "blue plume" issues associated with the retrofit installation of SCR systems on power plants burning medium to high sulfur coal. SCR retrofits tend to oxidize more of the SO_2 in the flue gas to SO_3, which can pass through FGD systems and condense outside the power plant stack as an acid mist. DSI has been effective in preventing such a mist plume. However, DSI is not in widespread use as a basic SO_2 control system. If these systems are as effective as U. S. EPA assumes, it raises the question of why they have not been placed in service to mitigate basic SO_2 emissions.

[33] <u>An Assessment of the Feasibility of Retrofits for the Toxics Rule</u>, US EPA, Office of Air and Radiation, March 9, 2011.

Faster retrofits

One might expect that as utilities gain experience with air pollution controls, this learning would allow future retrofit projects to be more streamlined, and faster. However, at some point, such learning reaches a point of diminishing returns, as the application of air pollution controls becomes a mature industry. For the types of hardware that U. S. EPA expects to be retrofitted to enable compliance with the proposed HAP rules, that point in time occurred perhaps in the mid-1980's, as utilities complied with 1971 vintage State Implementation Plans and New Source Performance Standards. Since that point in time, further experience was gained with eastern U. S. ozone control programs, and the acid rain program prescribed by the 1990 Clean Air Act Amendments, but by then the air pollution control industry was well established.

Countering this learning curve process is the exploitation of the best opportunities for retrofits. Air pollution regulations incorporating trading, like the acid rain program, allowed utilities to control emissions from those sites easiest to retrofit. By exploiting these sites first, utilities were able to minimize the cost of retrofits, and resulting electricity price increases. A consequence of this process was that those sites which have not yet retrofitted advanced SO_2 or NO_x control hardware will face more difficult retrofits. And at sites which have already added large control systems like FGD and SCR, finding available space to retrofit a FF often will be difficult. While the "learning curve" advantages diminish over time, the site congestion problem becomes worse. Site congestion can extend the planning and installation time for a project. **The net effect is that EPA's assumption of faster future retrofits is probably incorrect.**

Requirements of other regulations and the 10 GW of retirements

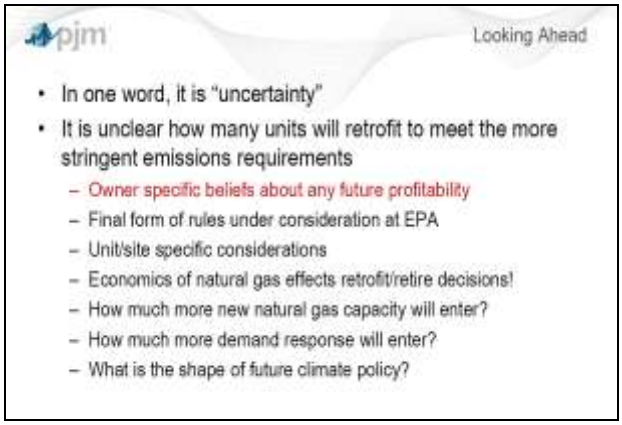
If the purpose of a feasibility analysis is to determine feasibility, then ignoring major compliance activities imposed on the same work force at the same time can only be viewed as disingenuous. When EPA considered resource constraints on the implementation of the 2005 Clean Air Interstate Rule (CAIR), the Agency considered not only the CAIR requirements but also other ongoing regulatory requirements.[34] An analysis of resource adequacy conducted on one of several regulations has limited value.

Early planning

U. S. EPA is correct in stating that these regulations, and the other regulations under development and cited by U. S. EPA, are known to be coming. However, the implicit assumption that utilities can begin designing and ordering compliance hardware before they know what the basic requirements are is unsupported. It will be difficult for utilities to make decisions even when a final HAP rule is promulgated, given the approach of additional regulations with additional requirements for capital investment. Consider the industrial boiler HAP rule promulgated by U. S. EPA in the spring, 2011. Between its proposal in June 2010, and promulgation in March 2011,[35,36] the rule changed dramatically. As a result, U. S. EPA's estimate for the total compliance costs for all affected existing units burning solid fuels decreased from $2.2 billion per year (proposed rule), to $0.85 billion per year (final rule). An electric utility with <25 MW unit or an industrial party with an industrial boiler owner who made financial commitments based on the proposed rule would have likely have made a poor decision.

[34] Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule), 70FR25216, May 12, 2005.
[35] National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, Proposed Rule, 75FR32006, June 4, 2010.
[36] National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, Final Rule, 76FR15608, March 21, 2011.

U. S. EPA's confidence that RTO's are currently making plans for this wave of regulations, including the HAP rule, may similarly be misplaced. The PJM[37] presentation cited by U. S. EPA in the preamble summed up the industry's dilemma in one slide:[38]



The fact that PJM knows that additional regulations are being developed does not enable the RTO to take specific measures to ensure grid reliability. That ability will come when it is clearer which power plants will retrofit specific types of hardware, and which will retire – facts that cannot emerge until the final rules, i.e. all rules affecting air emissions, water intake and discharge and waste management, are promulgated. PJM's population served of >51 million means that one of every six consumers of electricity is in the PJM RTO.

Compliance information related to public power utilities

An APPA survey of public power utilities was conducted (July 2011) in order to obtain a better understanding of the procedures and time necessary for that segment of the generation fleet to comply with the proposed HAP rule. Specific questions related to:

- The characteristics of existing coal-fired generation, including existing air pollution control equipment, and potential compliance needs
- The timing and process of planning compliance, and how that might differ from that of an investor owned utility (IOU)
- The timing and process of obtaining financing for pollution control projects
- Permitting, detailed design, and construction processes at public utilities
- An overall assessment of the time required for the full compliance process, from initial planning through startup of new pollution control hardware.

Utilities owning approximately 14 GW of coal based generation capacity responded to the APPA survey. These represent over 50% of the coal based capacity wholly owned by public power utilities. Respondents ranged in cumulative capacity between 55 MW and 2200 MW, and averaged 610 MW of coal based capacity. Not all respondents addressed every question in the survey, but most provided a general description of their compliance process, and areas where they might differ from IOUs. The results of the survey are summarized by the following:

[37] PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. PJM has 163,500 MW generating capacity and >51 million customers.
[38] Op. Cit., Consideration of Forthcoming Environmental Rules, slide #20.

- About 20% of respondents planned to retrofit FGD,[39] and about 20% SCR[40] (typically the same utilities were retrofitting both). About one-half planned to replace or supplement existing ESPs with new FFs.[41]
- About one-fourth were moving forward with plans based on the notice of proposed rule (NOPR). Half were waiting until the final rule is promulgated, and the rest intended to wait until other pending environmental rules were finalized before deciding on a compliance approach.
- About three-fourths of respondents stated that they needed the assistance of engineering consultants for planning their compliance strategy. Such reliance is not unusual, even for IOUs, but several respondents cited their small size and/or remote locations as barriers to obtaining assistance from the larger, more qualified consulting firms. Additionally, several respondents cited a mandatory "public bid" process for selecting contractors (and purchasing equipment) which deterred some contractors and created additional delays in reaching compliance.
- **Public power utilities generally must receive approval from political bodies, such as an elected Board of Directors and a City Council.** Procedures vary by utility, but separate government approvals may be required for the compliance plan and the issuance of bonds to pay for the compliance projects. Several respondents noted that a public referendum is required in order for bonds to be sold.
- Planning periods averaged 17 months, and financing 8 months. However several respondents noted that budgets were addressed only once per year, and that public reviews of plans and funding could result in extended delays, including what one respondent called "hostile interventions."
- Respondents cited a range of criteria for deciding whether to retrofit an existing unit or retire the unit and replace the lost capacity with a new unit**. In determining the most important criterion affecting that decision, 38% of respondents cited the age of a unit or the capital cost of the retrofit project, 41% cited the average cost of electricity increase resulting from the retrofit project, and 21% cited the general uncertainty regarding the cost of future environmental regulations.** Stated differently, the basic logic used to model the HAP rule – minimizing future cost of electricity considering only the HAP rule – was not the critical criterion for compliance planning for most public power utilities. This is important to the issue of compliance timing because it suggests that modelers, including EPA's, may be using the wrong model logic to simulate responses to the proposed rule, and thereby projecting the wrong compliance strategies. **Different strategies (specifically, retirement versus retrofit) could have fundamentally different resource and timing requirements**.
- Over three-fourths of respondents expecting to add a FF for compliance stated that **space limitations at their sites would significantly increase capital costs**, compared to a site with adequate space.
- Responding utilities with multiple units to retrofit at the same facility expected to need an additional 12 months in order to address a second unit.
- For past retrofits of environmental control systems (FGD, SCR, FF, ESP), respondents reported an <u>average of 49 months</u> to address all activities from planning to startup. This average did not include the additional time needed to retrofit multiple units at one facility. It is important to note that this figure represents an <u>average</u>. As reflected in EPA's approach to establishing upper performance limits (UPLs) for HAP emission rates, average values should not be the basis for

[39] Those planning to retrofit FGD were all single-facility utilities, and they planned to retrofit the entire facility.
[40] One of these SCR respondents planned to retrofit 50% of his capacity; the remainder would retrofit 100%.
[41] The portion of the FF respondents' facilities retrofitting FFs generally ranged between 60-100% of total capacity.

setting compliance requirements. If one used EPA's approach of "percentiles" (i.e., select a value for which 99% of facilities would comply with the rule), **then the number of months needed for a single unit retrofit at a facility would range from 73 to 78 months, for "percentiles" of 90% to 99%.**

Adding 12 months for a facility requiring two retrofits would result in 85-90 months. However, four of the past retrofits described by respondents were either unusually faster or slower than the rest of the reported retrofits. Excluding these units as "outliers," which seems reasonable if one takes the "percentile" approach, would yield the same average (49 months), but a range of 54-65 months for the 90% to 99% UPL, or 66-77 months if a year is added for facilities retrofitting two units. Please see Figure 2 below for a visualization of the time needed to complete retrofits for compliance as compared to the time allowed by U. S. EPA.

- Unusual situations are not reflected by the above average, but probably fall within the range represented by a "90 percentile" approach. One respondent speculating on a future retrofit cited the need to replace a hot-side ESP with a FF. This change would mean that the air heater would no longer receive "clean" flue gas, since the fabric filter system could not tolerate the high temperature of gases entering the air heater, leading to reconfiguring the air heater to a "dirty" system, and relocating a major electrical subsystem within the existing unit. The respondent judged that this work could not be completed in 4 years.

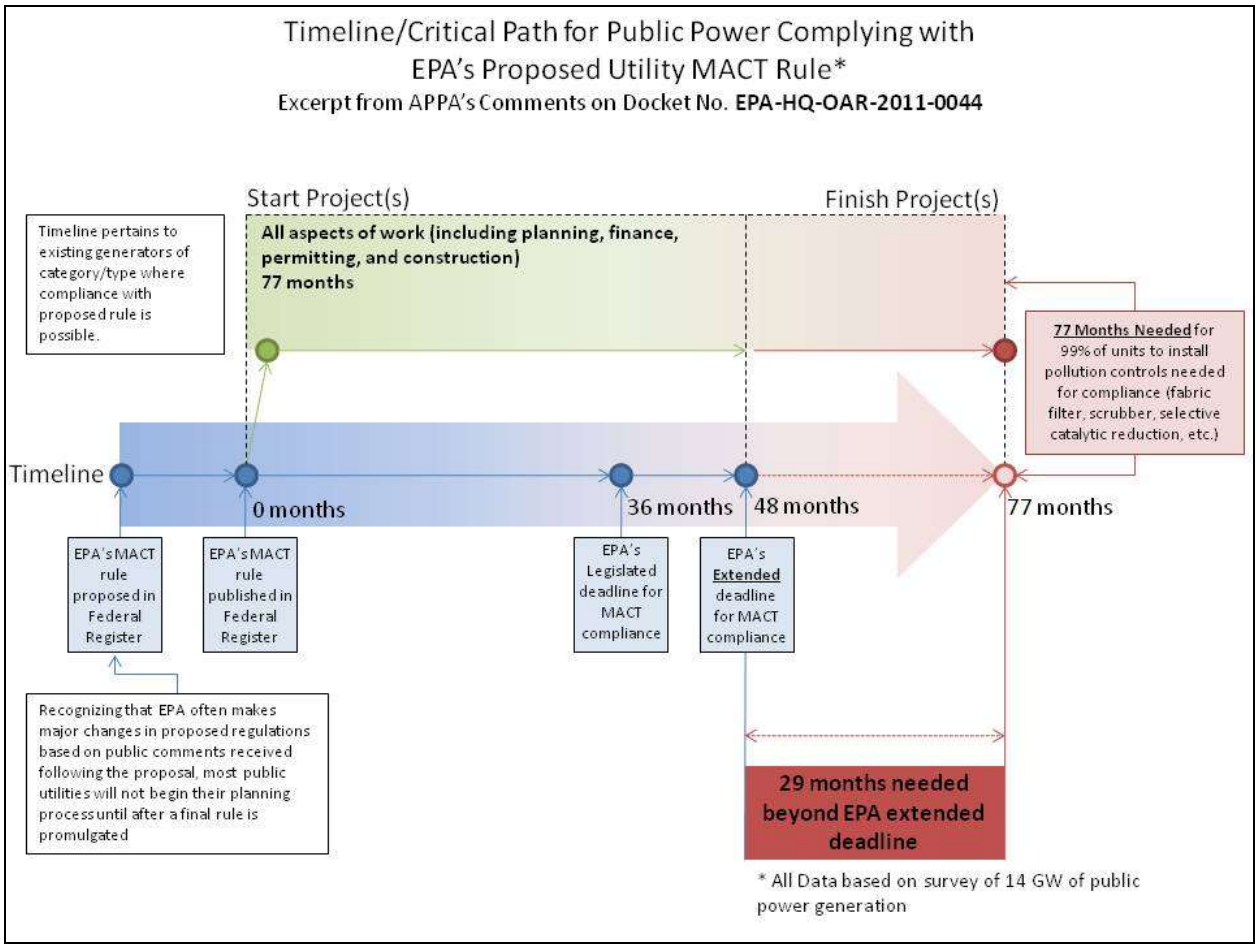


Figure 2: Visualization of timeline needed by utilities to install pollution controls for compliance as opposed to timeline allowed by U. S. EPA**.**

General conclusions and recommendations

It is clear that public power (not for profit) utilities face some procedural requirements **not** generally shared by investor owned utilities and independent power producers. These procedural requirements can extend the period of time needed by public utilities to comply with the HAP rule. For example, most public utilities must answer to a "Board of Directors," or equivalent body, as well as a City Council, or equivalent political body. Generally, both of these groups must approve major capital projects, such as retrofitting a FF on a power plant. In some cases, the process includes public participation. Public power (not for profit) utilities do not issue stock, so capital projects are generally financed entirely via debt. Subsequent to approving a project, a second review and approval process is usually required for public utilities to issue bonds, which are the primary debt vehicle for public utilities. In some, but not all, jurisdictions, bonds must also be approved by voter referendum. These review and approval processes can be time consuming, particularly if the government body only considers budget items once per year, or if a bond vote must await a general election.

The average public power utility is also smaller than the average electric utility. **Cumulative coal capacity averages about 417 MW for public power utilities, versus an average of over 1,000 MW for all utilities**. Several respondents to the public power survey expressed difficulty in attracting quality contractors due to the utility's small size relative to large IOUs competing for the same pool of contractors. Requirements for a public bidding process were cited by several public utilities as creating an additional barrier to securing top quality contractors. Smaller, less experienced contractors can require longer to complete a project than larger firms.

In general, respondents to the public power survey supported few of the key assumptions used by U.S. EPA in the agency's compliance time analysis. For example, U. S. EPA's expectation of significant planning activity prior to issuance of the final HAP rule was not supported by respondents. **Over 70% of respondents felt the need to see the final HAP rule before charting a compliance path, and some of those wanted to see the outcome of other pending U. S. EPA rules before making decisions. This is a significant issue for public power utilities, as noted above, because of their formal, multilevel oversight and approval process**. Municipal entities cannot afford the economic or political consequences of planning missteps.

Respondents also challenged U. S. EPA's reliance upon DSI, instead of more traditional FGD systems for acid gases. As noted previously, 20% of respondents planned on retrofitting FGD systems. On the other hand, respondents supported EPA's expectation for a large number of FF retrofits. About one-half of respondents planned to retrofit a FF system.

Based on the preamble[42] and EPA's supporting feasibility study,[43] it appears that EPA believes that the regulated utilities can achieve compliance within 50 months of the signing of the final rule (48 months after publication in the Federal Register). As noted above, the preamble states that three years is "necessary," but does not say that it will be sufficient. The U. S. EPA feasibility paper says that, if some utilities get started before the rule is finalized, then "many of the needed retrofits" could be "installed by January 2015 with some needing up to an additional year." These dates are coincidentally identical to the compliance limits specified in Section 112 of the Clean Air Act. EPA appears comfortable with the fact that it is proposing a rule with compliance dates which are unachievable, absent favorable execution of discretionary extensions by permitting authorities, but which are achievable even in that case only if regulated facilities embark on compliance strategies before they know what the regulation will require. This exceedingly thin endorsement of a 3-4 year compliance period is not well supported by the past experiences of public utilities. **As described**

[42] Op. Cit., National Emission Standards, May 3, 2011.
[43] Op. Cit., An Assessment of the Feasibility.

above, a survey of past retrofits by public power utilities suggests that the regulations would need to provide 66-77 months to accommodate facilities with multiple retrofits and to ensure that 90% to 99% of retrofit projects could be completed within the compliance date deadline.

U. S. EPA's lack of consideration of resource requirements by other rules under development by the agency, and the assumption "*that almost all future APC retrofits can be completed far more quickly than were historical APC projects*" are both causes for concern. U. S. EPA acknowledges that there are at least four other major power plant rules which will be adopted over the next year, but offers no insight into how resource demands for those rules will impact the timing of compliance with the HAP rule. Those additional engineering and construction resource demands could be large, particularly if the cumulative effect of the rules leads to early retirement of existing coal units and construction of replacement power. U. S. EPA's vacant assertion regarding future versus past retrofit schedules ignores the fact that recent rules involving emissions trading (the acid rain program, the NO_x SIP-call) created a strong incentive to control the most easily retrofit units first. Remaining sites will face inherently more difficult and time consuming challenges. The most common retrofit technology projected by the U. S. EPA's analysis is FF technology. Many existing public power utilities will be challenged to find space to retrofit those large units, and disruptive installations tend to take longer to install.

Finally, it should be recognized that public power utilities are extensions of state and local governments. U. S. EPA's analysis of the timing of compliance includes no consideration for the special compliance schedule challenges that public power utilities face. Both the Unfunded Mandates Reform Act of 1995 and Executive Order 13132 create imperatives that U. S. EPA minimize regulatory impacts on local governments. U. S. EPA acknowledges its obligations to public utilities in the preamble,[44] but appears to believe that convening meetings with national associations representing state and local governments relieves the agency of the need to propose and evaluate substantive alternative regulatory options that address the needs of those government entities.

Time Constrained Feasibility: Why Categorized Extension for Governmentally Owned Utilities Is Justified

APPA urges that U. S. EPA grant publicly owned utilities an extra year for compliance beyond the three years provided by the Clean Air Act. 42 U.S.C. §112(i)(3)(A). As outlined above, publicly-owned electric generating facilities must comply with administrative and regulatory procedures for bidding and financing pollution control and repowering projects. Notice requirements and public contracting procedures for bidding the purchase, design and installation of such equipment are also mandated under city or state laws so that the public has the opportunity to monitor, contribute to, and comment on how public funds are used for large expenditures that will be necessitated to meet the pollution control requirements of the proposed MACT standard. Such local governance duties for these expenditures and actions will add up to three years to compliance periods required to retrofit or repower units to meet the proposed standards, according to APPA's survey.

In addition to the inability of most publicly owned utilities to compete economically with privately owned utilities for the already limited supply of skilled design and construction engineers and available technology to meet the industry-specific MACT requirements, government-owned utilities will need to meet unique local, state and federal requirements regarding bond issuance for the purchase of equipment and other competitive bidding processes for implementation of the requirements. Based on prior U. S. EPA precedent and these unique circumstances, more time is required for publicly-owned generating facilities to purchase controls and approve contractors. Additionally, more time is needed for installation

[44] Op. Cit., National Emission Standards, 76FR25084 – 25087.

of compliance equipment. The U. S. EPA should provide in the final EGU MACT rule for a **categorical extension** for compliance for publicly-owned or governmental facilities to meet the new MACT standard based upon time-constrained feasibility. This categorical public power extension is based upon the feasibility for local government and must be considered under UMRA and the Clean Air Act. Under Clean Air Act the U. S. EPA has the authority to set the deadline based upon feasibility. APPA is aware that "feasibility" has been addressed for other Clean Air Act deadlines (NAAQS) in the case of the steel industry when the "feasibility" in installing new controls was either economic or technical. (See U. S. EPA's RACT/ BACT Guidance.) APPA believes this is a different type of "feasibility," but one consistent with the common parlance or meaning of "feasibility."

A clear reading of Executive Orders 13563 (Improving Regulation and Regulatory Review) and Executive Order 13132 (Federalism) shows that the U. S. EPA failed to follow their obligations under either Executive Order.

Executive Order 13563's Section 4 makes it clear that all agencies (including Independent agencies such as the U. S. EPA) shall identify and consider flexible approaches for compliance to their proposed rule. In this instance the U. S. EPA has not proposed any of the regulatory options to reduce burdens and maintain flexibility.

> Sec. 4. Flexible Approaches*:*
>
> *Where relevant, feasible, and consistent with regulatory objectives, and to the extent permitted by law, each agency shall identify and consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public. These approaches include warnings, appropriate default rules, and disclosure requirements as well as provision of information to the public in a form that is clear and intelligible."*[45]

Further, the Executive Order on Federalism (EO 13132)'s principal tenants were ignored in Sections 1, 2 and 3 by the U. S. EPA. Please see pp 9-14 of APPA's comments. In specific, Executive Order on Federalism says:

> Section 3(b) of Executive Order 13132:
>
> *"Where there are significant uncertainties as to whether national action is authorized or appropriate, agencies shall consult with appropriate State and local officials to determine whether Federal objectives can be attained by other means"*

APPA notes that the U. S. EPA has failed to carry out its regulatory obligations of the Unfunded Mandates Reform Act of 1995 (in addition to those critiques offered on pp 8-16) in its nominal meeting with the "Big Ten" on October 27, 2010. Section 203 of UMRA (2 USC 1533) says:

> SEC. 203. SMALL GOVERNMENT AGENCY PLAN.

[45] Executive Order 13563 of January 18, 2011, Improving Regulation and Regulatory Review, Federal Register /Vol. 76, No. 14 / Friday, January 21, 2011

(a) EFFECTS ON SMALL GOVERNMENTS.—Before establishing any regulatory requirements that might significantly or uniquely affect small governments, agencies shall have developed a plan under which the agency shall—
(1) provide notice of the requirements to potentially affected small governments, if any;
(2) enable officials of affected small governments to provide meaningful and timely input in the development of regulatory proposals containing significant Federal intergovernmental mandates; and
(3) inform, educate, and advise small governments on compliance with the requirements.

APPA's recommends a time-constrained feasibility categorical time extension under E. O 13132, 13563 and UMRA of 1995.

1. U. S. EPA Has Granted Categorical MACT Compliance Extensions Before in Unique Circumstances.

While the Act contemplates that the administrator (or a state with delegated Title V Permitting authority) would generally grant such extensions on a case-by-case basis for an existing source up to one additional year. 42 U.S.C. §112(i)(3)(B), the agency also has used this authority to grant category-wide industry MACT compliance extensions upon a specific showing of need. See e.g. Subpart G Hazardous Organic NESHAPS, 60 Fed. Reg. 5320 (Jan.27, 1995) (discussion of several categorical compliance extensions from MACT compliance); National Emission Standards for Chromium Emissions From Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks, 62 Fed, Reg. 4463(Jan. 30, 1997) (partial extension for all sources in California); NESAHPS for Group I Polymers and Resins 62Fed. Reg. 1835 (Jan 14, 1997); National Emission Standards for Hazardous Air Pollutants for Shipbuilding and Ship Repair (Surface Coating) Operations, 61 Fed. Reg. 30815 (June 18, 1996) (U. S. EPA has learned that sufficient time was not provided to prepare the implementation plans and establish the necessary inventory management systems to ensure compliance with the standard.)

U. S. EPA also has denied requests to grant a category wide extension if sufficient basis was not demonstrated. For instance, with respect to implementation of subpart H's SOCMI leak prevention equipment, commenters argued that the 6-to-18-month compliance period in proposed subpart H did not take into consideration the implementation problems that could arise during installation of required equipment. U. S. EPA did not revise the compliance schedule as requested "because the commenters did not provide any information that would justify establishing a source-category-wide compliance schedule similar to that provided in subpart G. Due to the lack of detailed information on equipment changes and installation schedules, the U. S. EPA thought that case-by-case compliance extensions would be sufficient to address any implementation problems that might arise. In issuing the final rule, the U. S. EPA added a provision, Sec. 63.182(a)(6), to clarify that individual extensions of compliance may be requested for installation of equipment required by subpart H. 60 Fed. Reg. 5320 (Jan. 27, 1995).

2. Publicly-Owned Electric Generators Meet the Statute's Standard for Granting Compliance Extensions.

The preamble to the proposed amendments to the General MACT Provisions describes some of the situations in which a compliance extension for MACT compliance is authorized under the Clean Air Act.

The compliance extension under section 112(i)(3) is available for adding controls and other compliance measures requiring time beyond that which is anticipated in establishing the compliance date for NESHAP. For example, other compliance measures may include obtaining or implementing technology hardware or software systems and process changes to accommodate pollution prevention or other emission reduction measures. Such a compliance extension is not appropriate for the failure of an owner or operator to properly plan and carry out the installation by the compliance date. However, there may be situations where sources acting in good faith to anticipate and fulfill their compliance obligations can still not achieve compliance in a timely manner because of circumstances or events not entirely of their own making. Work stoppages at a control equipment supplier's factory are cited as one example of a reason that sources, acting in good faith, might not be able to achieve compliance on time. Shortages of skilled design and construction engineers who are needed to build new facilities to meet relevant standards, as well as shortages of available technology to meet the demand from sources who must comply with industry-specific MACT requirements, may also contribute to delays in achieving compliance.

APPA's members and other publicly-owned utilities meet these additional situations, when a compliance extension is appropriate. **For administrative ease and resource savings on the part of governmental entities and U. S. EPA officials, it would be prudent to approve a categorical extension for compliance with the final utility MACT to avoid additional justification and review by cities and other governmental entities as well as the federal government**. While notice, contracts and other bidding processes and bond approval requirements may vary somewhat among cities, they are very much the same.

APPA Believes U. S. EPA Has Provided a Flawed Regulatory Impact Analysis:

U. S. EPA's RIA projects that only three percent of the electric utility industry's coal-fired capacity will become uneconomical due to the proposed rule because of age, size, or lessened hours of operation. U. S. EPA has failed to recognize that many older coal-fired power plants have considerable space constraints and may only be able to "build up" if they are installing a baghouse. The U. S. EPA RIA failed to identify how many of the public power units will be implementing control technologies under separate regulations, including:

- CSPAR or Regional Transport (RT) in 31 states.
- 316(b) cooling water, entrainment and impingement studies and the subsequent control technologies.

Further, the U.S. EPA has a series of anticipated revisions to the existing National Ambient Air Quality Standards (NAAQS) for tropospheric ozone, $PM^{2.5}$, SO_2 and NO_x standards. These, combined with state implementation plan (SIP) changes and revisions to effluent guidelines (chlorine, boron, mercury, etc.), may well make power plants subject to being offline for many weeks and perhaps months over the next five-plus years.

Perhaps most importantly the U. S. EPA NESHAP proposal calls for 165 GW of fabric filters for the existing coal-fired power plants and perhaps half of the U. S. coal fleet. In total, U. S. EPA's analysis shows 354 gigawatts of control technology being installed. APPA believes this is a significant underestimate of the needed controls and additional costs. Further, APPA believes that the U. S. EPA underestimated the impacts on some regions that will have more power plants under construction and retrofit at the same time. These plants tend to be in the upper and lower Midwest, Southeast and Southwest. Other reliable estimates performed by industry experts show 531 gigawatts of control technology being installed.[46]

DSI, the sorbent technology selected by U. S. EPA for its relative low cost, can cause significant technical problems, APPA would be very surprised to see half of the industry install dry sorbent injection (DSI) by 2015 (RIA, Section 8-13). APPA finds it rather remarkable that the U. S. EPA assumes that the DSI technology will work so effectively for all coal types without any technical or historical basis. APPA believes that the U. S. EPA has presumed effectiveness based only upon limited use of DSI at a few plants. This type of technology choice does not consider all of the factors facing utilities and further contributes to the inaccuracies of the U. S. EPA's Regulatory Impact Analysis.

APPA believes that the U. S. EPA has grossly underestimated the number of coal-fired generation retirements at only 9.9 GW, which is only three percent of all coal-fired capacity by the year 2015. APPA believes that the U. S. EPA chose to view the proposed EGU NESHAP in isolation and not in the CSPAR (the replacement of the Regional Transport Rule). Many published studies project retirements above 40 GW, when viewed in combination and under certain circumstances.

U. S. EPA's RIA offers peculiar reference (RIA p. 10-18) to the APPA and NRECA request (verbal and written) for subcategorization. Neither the proposed rule nor the RIA adequately explained why more subcategorizations were not made. The RIA (RIA section 10-18 under "Subcategorization") specifically refers to the SER panelists who recommended units that generate for wind generation or other purposes such as combined heat and power (CHP). Perhaps most significantly the EPA declined to propose a subcategory for small or rural (geographically isolated) units. This decision not to propose a small unit subcategory is bad enough but is made all the worse since the U. S. EPA offered no use of GACT controls. **OMB's own comments in the RIA agree that GACT and management practices would be effective** (pp. 10-21 of RIA).

As noted before on page 19, APPA points out that the U. S. EPA's Regulatory Impact Analysis (RIA) states that the U. S. Small Business Administration (and presumably OMB) expressed concerns that the U. S. EPA failed to identify and offer as regulatory alternatives a number of options on the proposed EGU MACT rule before it was proposed. None of those recommendations for subcategories (by size, by fuel type, by generation technology type or by geographic isolation (rural)) were even proposed by the U. S. EPA in the proposed rule. The U. S. EPA's proposed rule did not explain why none of these recommendations were considered. That explanation in the proposed rule is required under SBREFA and Unfunded Mandates Reform Act (UMRA) and both of these statutes deal with regulatory decisions for local government-owned utilities. The proposed rule did not mention any plans to offer an additional year to these smaller entities and was dismissive of the serious reliability issues for smaller communities (especially in the Midwest) where many of the retrofit or conversions to natural gas will take place.

[46] American Coalition for Clean Coal Electricity

EPA's own Regulatory Impact Analysis and economic analysis says that 97 municipal or state utilities will have a compliance cost of $666.3 million in annual direct compliance costs

As previously mentioned, the U. S. EPA's cost analysis does not factor in other costs such as the cost of purchasing wholesale power off the market, the costs for fuel switching to natural gas or the inability to sell coal ash or coal combustion residuals (CCR) to the cement industry.

In addition to poor analysis in the three-year compliance date feasibility presumption about DSI technology for all coal types, and "check the box" exercises with the December 2010 SBREFA SER, APPA also notes that the U. S. EPA did a very poor job in its Unfunded Mandates Reform Act (UMRA) analysis.

"Section 202 of UMRA requires the EPA to consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, of least burdensome alternative if the administrator publishes an explanation why that alternative was not adopted."

APPA refers the U. S. EPA to the full critique of UMRA and SBREFA on page 8.

In section 8.10 (Projected Fuel Price Impacts) of U. S. EPA's Regulatory Impact Analysis for the Toxics Rule, the U. S. EPA states that consumer natural gas price impacts from the rule are expected to range from a 0.6% to 1.3% increase. APPA believes this is a significant underestimation and encourages U. S. EPA to revaluate impacts of the Toxics Rules projected price impacts using a range of natural gas prices (and other key variables). In its alternative case analysis, U. S. EPA should at a minimum use a set of natural gas prices that include a hedge on the bet that natural gas prices will stay low for the foreseeable future.

Long-term natural gas prices are notoriously difficult to predict and monthly spot prices have varied in the last five years from as high as $13 per MMBtu to below $3 per MMBtu; as far as we know no government agency or consultant has a consistent track record getting them right. Despite the popular view that shale gas makes natural gas available at low prices as far as the eye can see, policy analysis should take a more neutral view and consider a plausible range that natural gas prices take, recognizing forecasting difficulties and uncertainty. The U. S. EPA should be particularly careful with the natural gas price assumption given its recognition that higher natural gas prices force more coal-fired generation to retire. A graph of average national monthly gas prices can be seen in Figure 3 on the next page. Significant variability in prices can be seen.

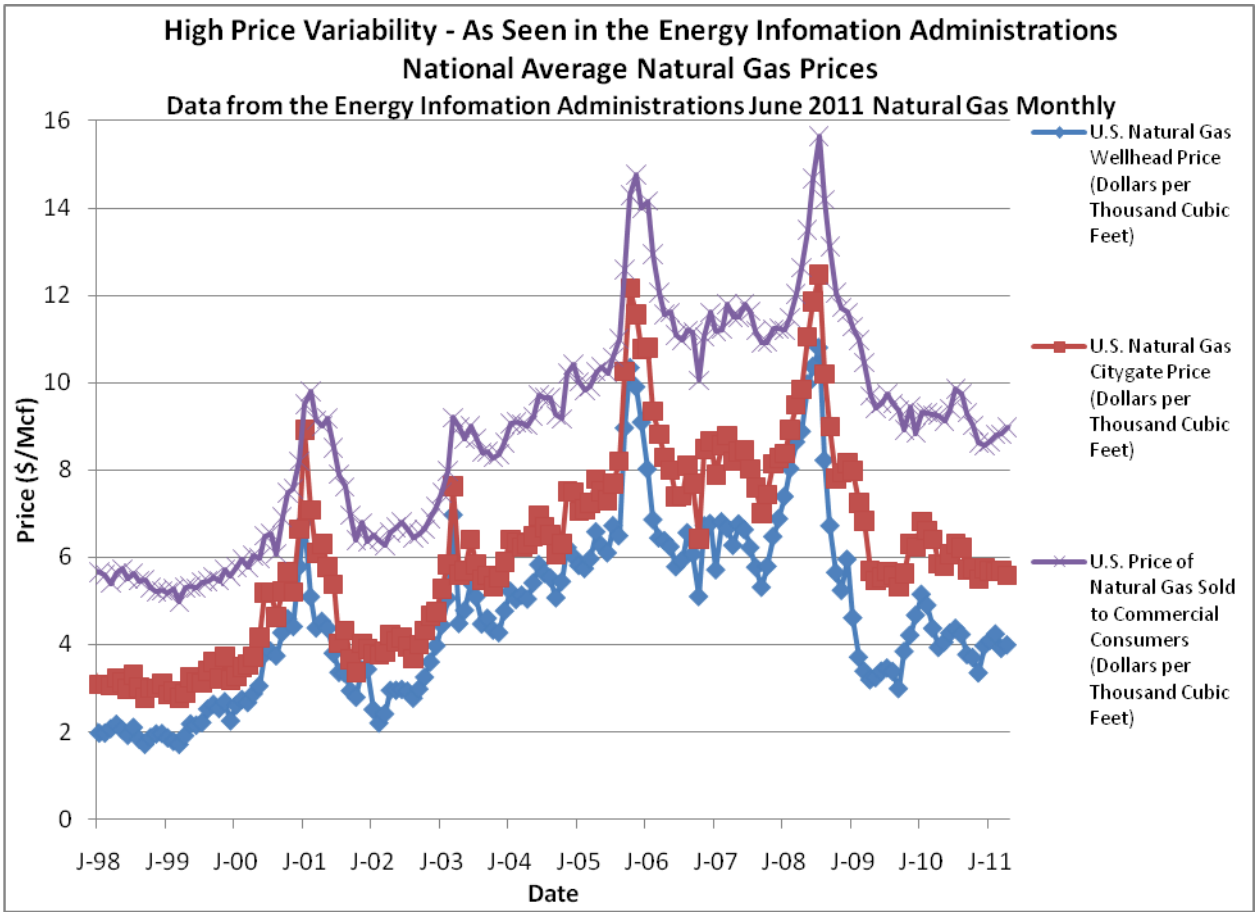


Figure 3: Average natural gas prices at the wellhead, citygate, and for commercial consumers from EIA data

Projecting natural gas prices is further complicated because (a) industrial load and demand for gas has not rebounded to 2008 levels of consumption, and (b) liquefied natural gas exports may influence domestic natural gas prices considerably. It has been noted in the energy trade press that exports from built or pending liquefied natural gas terminals may affect as much as 23% of existing U.S. natural gas production.

The natural gas prices produced by U. S. EPA's modeling are driven by the assumption on the size and economics of gas resource base. ICF, the company that produces the IPM model used by U. S. EPA to assess the impact of air regulations, prepared an alternate case in which it reduced the shale resource assumption by 31%. Unfortunately, there are no additional alternates testing other key assumptions. This should be remedied. The increase in natural gas prices produced by assuming a lower resource base amply illustrate how important the resource base is to the natural gas prices projected by ICF's IPM model. This increase in prices can be seen in Table 2.

Table 2

Natural Gas Prices for IPM Policy Case Vs. Lower Gas Resources Case (2007 $/MMBtu)				
	2012	2015	2020	2030
Policy Case				
Henry Hub		5.49	4.77	5.90
Delivered		5.73	4.99	6.22
Lower Gas Resource Case				
Henry Hub	4.98	5.51	7.64	8.50
Delivered	5.19	5.71	7.88	8.91

There are a number of other factors that could lead to higher natural gas prices that are not reflected in the IPM assumptions or the model structure. <u>U. S. EPA should address these factors in order to more accurately model gas prices:</u>

- Higher natural gas demand for use in vehicles (a la The Pickens Plan) or some amount of transportation electrification
- Constraints either on shale resources allowed to be extracted due to regional opposition or reflect drilling restrictions or a cost adder for environmental remediation
- Starting oil prices "adapted from AEO 2009," of about $62/bbl for 2011 are well below current oil prices
- No documentation of any indication that the gas market module of IPM reflects the drilling lease inventory buildup that may be causing some producers to drill at less economic prices in exchange for cash flow and retention of their lease options
- Unclear what the production per well or depletion assumptions are or whether they have been updated (i.e., lowered) for the shift to more shale production
- Figure 10-7 from U. S. EPA's proposed rule provides the resource cost curves but no documentation of how they were derived or how the quantity able to be produced economically at prices below $14 per MMBtu was determined. Page 10-13 of U. S. EPA's proposed rule indicates that the undiscovered gas resource is "assumed" to grow at 0.2% per year for conventional gas and 0.75% for undiscovered gas. Nothing provides the basis for testing that assumption's validity. The discussion admits that technology drives the ability to produce undiscovered resources but does not test the technology assumption and no curves are provided at all for the existing discovered resource base.
- The model covers North America only, so it must be fed an exogenous assumption on LNG imports (or exports) and cannot predict or capture changes in world-wide development and trading of natural gas.

Comments related to general policy considerations

The Final MACT Should Provide For An Administrative Compliance Procedure for Utilities When They are Unable to Comply with the MACT Compliance Date.

If U. S. EPA fails to take the actions recommended by these comments (77 month categorical extension) to reduce the regulatory burdens of complying with the proposed MACT standards, the agency must

provide a streamlined administrative procedure for utilities that operate power plants that will not be able, through no fault of their own, to comply with the standard on the compliance date. (Other types of facilities also should be able to demonstrate that they meet the qualifications for such compliance extensions as well.) APPA recommends using existing procedures that already exist within the Clean Air Act's existing Title V operating permit program for modification of permits with compliance plans to streamline the procedure for compliance extensions, which we favor over use of other discretionary enforcement procedures that U. S. EPA currently uses for noncompliance. As we explain below, we believe that the transactional costs and the uncertainty of the outcome of the use of the current U. S. EPA enforcement authorities make them unattractive and inappropriate, particularly for public power plants.

One of the benefits of this program would be to reduce the administrative burden on the U. S. EPA and state agencies. Since 1997, EPA has brought enforcement actions for Section 112 air toxics violations in over 500 administrative penalty cases and nearly 100 judicial enforcement cases, some involving penalties and environmental projects over $1 million each. Many of these cases involve reporting violations but involve significant personnel demands on EPA regions and the Department of Justice. Without this administrative mechanism for streamlining noncompliance schedules into Title V permits, the U. S. EPA, Department of Justice, and their state counterparts could be overwhelmed with the additional enforcement burden presented by government-operated utilities that cannot comply timely with the MACT standards. By "pre-programing" the minimum components that a compliance schedule would have and establishing a time frame for coming into compliance with MACT, these additional burdens on the federal and state government enforcement programs can be avoided but state and federal enforceable compliance milestones would be in place. Also, state and local governments that operate regulated utilities would have certainty and enforceable milestones to meet and would avoid the potentially overwhelming transactional legal costs associated with traditional EPA enforcement. As a result mercury reductions would be achieved without additional costs and in a manner that provides the public with the assurance that these reductions are being made without additional costs to communities.

EPA's criminal enforcement program opened 346 new environmental crime cases in FY 2010.[47] Many states have experienced losses in employees at state regulatory agencies as a result of cut backs and lost revenue from permitting fees. This proposal is designed to place the least possible burden on state and Federal EPA, consistent with Unfunded Mandates Reform Act (UMRA).

APPA discusses these procedures below and recommends how U. S. EPA should "streamline" the adoption of compliance plans even further.

1. <u>Streamlined extended compliance schedules should be provided to public power (and other entities) that can demonstrate need for additional time</u>.

APPA has enumerated in good faith the reasons that many municipally operated power plants are likely to be unable to comply within the three-year MACT compliance period, even if U. S EPA provides the additional year for all public power plants in the final MACT standard, as APPA requests. These reasons include, but are not limited to:

- U. S. EPA's mistaken assumption that cities can legally begin designing and ordering compliance hardware before issuance of the final MACT;

[47] US.EPA Office of Enforcement http://yosemite.epa.gov/opa/admpress.nsf/ab2d81eb088f4a7e85257359003f5339/78264683b1a9874e852577f10059b840!OpenDocument)

- Public power's heavy reliance on outside engineering and union labor and difficulty competing with other utilities because of most cities' bidding procedures;
- The iterative state and locally mandated administrative procedures for the receipt of bids and award of contracts;
- Federal, state and municipal requirements of public referendums and the issuance of public debentures/bonds for the purchase and installation of pollution control equipment.

In view of these unique public power issues that will likely result in the many public power utilities being unable to meet the MACT compliance date, APPA submits that the final MACT should establish an "Extended Non-Compliance Schedule" procedure for public power generators (and other sources that can demonstrate need for additional time).

2. Discretionary U. S. EPA enforcement procedures are too uncertain, and the transactional costs that they entail are inappropriate when cities know they will be unable to meet the MACT rule because of necessary procedures applicable to local governmental bodies.

The Clean Air Act provides for a battery of civil and criminal remedies, including noncompliance penalties, civil penalties, injunctive relief and jail time, for failure to comply with Clean Air Act standards and emission limitations. These remedies are administered at the discretion of the agency's enforcement officials in conjunction with officials in the Department of Justice's Environment and Natural Resources Division (DOJ ENRD). In most situations, the Agency favors use of consent decrees for entering into agreements with noncompliance sources because such legal instruments are judicially enforceable and can be judicially modified. Typically, the U. S. EPA and DOJ will issue a Notice of Violation, negotiate with officers and other legal representatives of the non-complying source and enter into an agreement which is filed the same day as a judicial complaint in the federal court with jurisdiction over a particular entity. Such process involves countless hours, attorney fees, the resources of individual federal district courts, lengthy periods of time and UNCERTAINTY. U. S. EPA enforcement policy also dictates the need for monetary penalties and supplemental environmental policies when noncompliance involves federal emission limitations. If a penalty will exceed certain amounts, U. S. EPA enforcement policy also dictates several levels of agency review before the consent order can be finalized, and such agreements must be published for public notice and comment under section 113(g) of the Clean Air Act before they are final. While U. S. EPA enforcement officials also have the sole discretion to utilize Administrative Orders on Consent (AOCs) without DOJ oversight, the procedures for their issuance also involve case-by-case review and determinations, though AOCs typically involve far less transactional delays and resource costs.

Since many of APPA's public power utilities are likely to be unable to comply with the MACT compliance date, even with a one year extension, APPA submits that the typical enforcement procedures are inappropriate. Moreover, because municipal entities are often cash-strapped because of economic conditions and are confronting disproportionate compliance costs (in comparison with other entities) and because they are not-for profit, U.S. EPA should provide for another streamlined procedure for sources to outline compliance milestones which can be incorporated through streamlined procedures in their Clean Air Act federal operating permits. We submit that through these processes, there is more likelihood of equal treatment between entities in various parts of the country (a level playing field, if you will) and greatly minimized transactional costs and legal resources exacted from municipalities that require additional time to come into compliance.

3. Public power utilities will not reap benefits from being out of compliance with the MACT.

Moreover, because public entities are not reaping monetary benefits from failure to comply on time with the MACT, these procedures are equitable. Further since such entities are acknowledging they are

violating the Clean Air Act MACT requirements, they bear the onus of noncompliance. Also, Section 112(d)(4) of the Clean Air Act does not preclude the Agency from identifying other means in a Section 112(d) MACT standard for a non-complying source to bring itself into compliance. Finally, if a public power plant violates the milestones in its compliance plan, recordkeeping and reporting procedures for a responsible officer will require expeditious notification of the State and EPA of noncompliance, and opportunity for further enforcement actions with penalties, etc.

4. Part 70 Operating Permit Procedures Provide Procedures for Compliance Plans, Which EPA Can Streamline Further in The MACT by Allowing Such Plans to Be Incorporated Through Minor Modification Permit Procedures.

Title V Compliance Schedules and Reopener Process: APPA urges U. S. EPA to provide **in the final MACT rule** an adoption of MACT compliance schedules through minor permit modifications of a source's Title V federal operating permits. We explain below why this streamlined procedure should be relied on in lieu of judicial or administrative consent decrees where cities and EPA and DOJ would have to incur unnecessary transactional costs. We also explain why the Title V rules allow EPA to provide in a standard for the use of minor permit modifications which already require notice and public comment to streamline further the incorporation of compliance schedules for entities that cannot comply on the compliance date *even if EPA provides, as APPA hopes, for automatic compliance extensions.*

Title V of the Clean Air Act is applicable to operating permits for all major Clean Air Act sources required the States to adopt procedures for states and EPA to adopt in operating permits Schedules of Compliance. A Schedule of Compliance is defined by Section 501(3) of the Act as:

> *"a schedule of remedial measures, including an enforceable sequence of actions or operations, leading to compliance with an applicable implementation plan, emission standard, emission limitation, or emission prohibition."*

See both sections 42 U.S.C. §7661 (a) and 42 U. S. C. § 7661 (3).

APPA also believes that such compliance schedules could be processed with public comment under 40 CFR §70.(e)(2)(i) (B) as "minor permit modifications" *if, as required by this provision*, the procedure for inclusion of the compliance schedule is provided by the MACT standard. In other words, to avoid the lengthy administrative procedures required by the major modification procedures of 40 CFR Section 70.7(e)(4) for processing significant permit modifications, EPA can "pre-program" these changes as minor permit modifications requiring the public power authority to use the procedures for submitting complete applications for approval of a compliance schedule for review by State permitting authorities and continue to operate in compliance with those new requirements unless denied by state authorities. Such procedures also require notice and public comment with proposed permit modifications. By adopting a procedure (and we suggest a general permit modification form for MACT compliance extensions in the final MACT), U. S. EPA can avoid unnecessary, lengthy and costly transactional costs for municipalities and the federal government (and the judiciary) that would be avoided in prosecuting notices of violations and judicial consent decrees. Most important to the cities, it also would allow orderly and expeditious negotiation of extended compliance schedules in full view of the public through the procedures already established for reopening operating permits. (APPA also suggests that these procedures are fully consistent with EPA voluntary audit policies, except of course they would be anticipation of noncompliance rather than in discovery of past noncompliance.)

Demonstration of Qualification for Compliance Plans – A public power plant (or other entity) would submit an application for a minor permit modification for a compliance plan. Such application would be accompanied by a sworn statement by the responsible officer for the utility and city's mayor or city attorney that despite its best efforts, the public power plant in the jurisdiction cannot timely meet the final MACT standard. Such sworn statement shall be accompanied by affidavits of the efforts that the city had

taken to come into compliance and the reasons that it will be unable to comply on the MACT compliance date.

Contents of Compliance Plans: Requirements for MACT compliance plans would include enforceable compliance milestones such as dates for purchase of equipment, dates for contractual agreements for installation, dates for construction and installation of equipment, or shutdown of equipment, with dates if necessary for completion of repowering. Compliance plans also could provide for other contingencies and penalties for failure to meet milestones.

5. Alternatively the final MACT rule should provide for the use of Administrative Orders on Consent to Streamline the Adoption of Noncompliance Extensions.

If EPA determines that the potential burden on states permitting authorities in administering operating permit modifications for incorporation of compliance plans is too great, it should provide in the final MACT rule for administrative consent orders to provide for adoption of MACT compliance plans with milestones for purchase and installation of MACT-required equipment for retrofits or shutdowns of facilities with or without repowering. APPA believes that it is critical that these Administrative Orders are entered into without penalty, since noncompliance will not be to avoid compliance costs that other utilities are facing, but merely to move as quickly as is allowed by law to come into compliance with Clean Air Act emission limitations. In that regard, it would not be appropriate for cities to pay the U.S. or state treasuries penalties for noncompliance with the MACT.

6. It is likely that adoption of a compliance plan procedure requires additional public comment.

Even though the Title V and EPA's discretionary enforcement authority under the Clean Air Act exist for adoption of these mechanisms in the final MACT rule, we think that it would be appropriate for EPA to reopen the final MACT to take further comment on these issues, including the milestones for such compliance plans and the eligibility requirements for such compliance plans.

General Clean Air Act Section 111 Comments

APPA does not believe that the U. S. EPA has represented "best demonstrated technology" for the gas and oil units, and it is inconsistent with the Statute. There is no need for any revision of the standard for gas and oil units.

APPA's General Comments on EGU MACT and NSPS Proposed Rule

1. APPA believes that the U. S. EPA has made a significant error in its proposed rule on mercury under the NESHAP program by adding extraneous regulatory controls for acid gases and $PM^{2.5}$. APPA believes that the U. S. EPA study authorized only mercury reductions in order to protect at risk populations of young children, child-bearing women, and those persons who consume large quantities of fish and may therefore be exposed to the human health concerns associated with bioaccumulation of methyl-mercury. APPA does not believe that the U. S. EPA needed to add these additional regulatory requirements since $PM^{2.5}$ is controlled under ozone and regional haze regulatory programs and State Implementation Plans (SIP). Further, particulate matter is scheduled to be reviewed for residual risk, which may lead to tightening of ozone, $PM^{2.5}$, SO_2, and NO_x under the National Ambient Air Quality Standards (NAAQS).

APPA believes that the U. S. EPA should repropose the rule to require reasonable mercury reductions consistent with the intent of Section 112 of the Clean Air Act without the

extraneous control requirements on non-methyl mercury. APPA believes that this re-proposal should include subcategories for smaller systems (≤100 MW) that have limited physical space. Those units should only have to meet GACT controls or area source controls for mercury.

2. APPA believes that three years from the date of publication of the final rule is an unrealistic timeline for compliance, given the need for municipal government to conduct resource planning for fuels, issue and review Requests for Proposal (RFP), obtain financing or issue debt/bonds to pay for projects, and coordinate with contractors, labor unions, and crane operators, along with any permits needed for construction and transportation affected by major construction. Some smaller utilities may need to arrange to purchase power from other utilities or the market during planned outages to retrofit for EGU MACT controls. This timeline suggests six years to accommodate these complex steps. In some states, permitting agencies might require up to six months for permit approval processes. Since the Clean Air Act's "pollution exclusion" has been removed, utilities may well trigger New Source Review (NSR) and this permitting process can easily add an additional year to the original permitting time. This point is made especially pertinent considering the specific steps that must be completed for each additional control group that is added to a generating unit. The specific steps include, but are not limited to:

    a. Identifying the type of equipment needed
    b. Quantifying the basic design parameters for each control type
    c. Evaluating the balance of plant/ancillary changes that will be needed
    d. Determination of possibility of compliance, including further economic analysis

    These steps outline what is typically referred to as phase 1 engineering work. A municipality cannot reasonably expect to complete these steps and the additional phase 2 work, which includes final engineering, construction, tie in, and start up with testing, in less than 36 months. To that point, a detailed engineering study involving just the decision to add fabric filter technology to a utility showed that 34 percent of the fabric filter upgrades would take longer than 36 months. [48] See Appendix G

    Considering these facts, APPA strongly urges the U. S. EPA to provide an industry wide extension, as outlined on pages 62, to reduce the burden on electric utilities, state permitting agencies and the consumers of electricity who will pay for the compliance costs. APPA urges the U. S. EPA and OMB to consider this under the Unfunded Mandates Reduction Act (UMRA) and Executive Order 12866 on energy impacts as well as the Executive Order on Federalism. (EO 13132)

3. APPA is a member of UARG and endorses UARG's technical paper (found in Appendix H) on this proposed EGU or Mercury MACT and the proposed NSPS rulemaking pertaining to data availability, data analysis and the identification of conversion errors. APPA also endorses UARG's comments offered separately on EGU MACT monitoring.

4. EPA did not adequately subcategorize to accommodate many of APPA's small and medium sized public power utilities. In particular, EPA did not avail itself of the opportunity to use public power electric utility subcategory, rural subcategory, and many other fuel type subcategories. APPA endorses the establishment of a ≤ 100 MW sub-category that will reduce the costs of the proposed rule significantly but only affect 5% of the total electric utility sector.

[48] Feasibility of retrofitting fabric filter particulate matter control technology to the electric generating unit inventory, UARG paper, Edward Cichanowicz, 2011

5. APPA does not believe that the EPA sufficiently considered its ability within the Clean Air Act to use Generally Available Control Technology (GACT) for smaller emitters of air toxics. Section 112(d)(5) of the Clean Air Act authorizes the EPA to use less stringent emissions standards or work practices for area sources of hazardous air pollutants (HAPs). EPA has broad authority to set GACT standards that are less stringent than MACT standards. Alternatively, the U. S. EPA should make GACT available for smaller plants. The proposed Utility MACT blurs the distinction between pollutants and the sections where they should be regulated in the Clean Air Act. This is problematic because there are many APPA member plants that would qualify as area sources had the U. S. EPA not combined two sections of the Clean Air Act. GACT has been used in the electroplating, dry cleaning and halogenated solvents industries MACT rulemakings in order to reduce costs and regulatory burdens. APPA had, along with NRECA, requested the use of GACT during the Dec. 2, 2010 SBREFA SER panel and this reasonable request was ignored.

   It seems inexplicable to APPA that the U.S. EPA would not use GACT in this rulemaking after being advised by both electric cooperatives and APPA member utilities that this would be an optimal way to reduce regulatory costs and achieve a reduction in toxic air pollutants. Additionally, APPA thinks it is strange that the U. S. EPA did not include GACT in the EGU MACT proposed rule after having allowed GACT and using GACT in the ICI Boiler MACT.[49] APPA and NRECA filed comments and discussed GACT during the December 2, 2010 SBREFA SER meeting so the EPA had plenty of notice to accommodate this option, which is provided for small emitters in the Clean Air Act.

6. EPA's feasibility and cost analysis did not adequately address physical space and age of plant issues when setting Best Demonstrated Technology (BDT), MACT and NSPS. In not addressing the age and space issues associated with including so many control technologies, the EPA has wrongly produced a rule that will make older plants and smaller plants unable to meet the new standards.

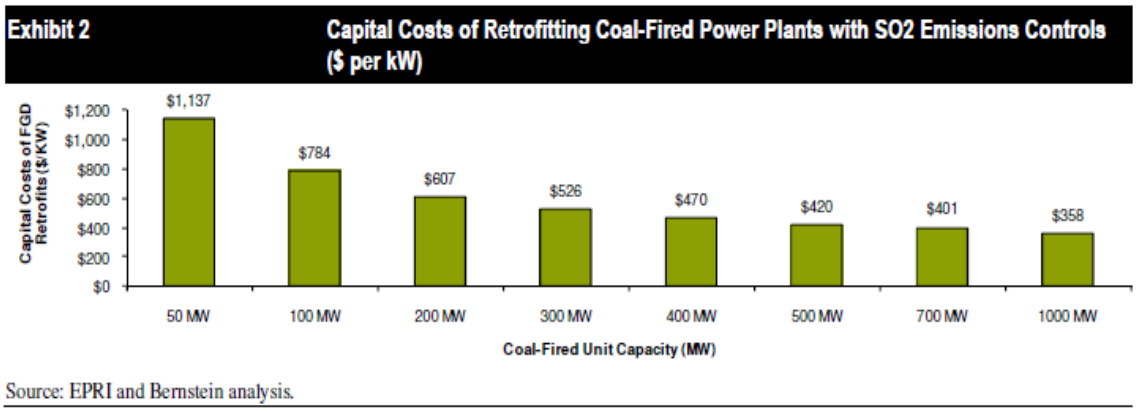
7. The various reports of projected plant closures under various EPA regulations—including EGU MACT - suggest the closures will far exceed EPA's projected possible closure of 9 GW.

   - SNL Financial (Feb 2011) report identifying 14,000 MW to retire between 2011 and 2020.
   - Brattle Group's forecast that 67,000 MW of existing coal-fired power plants to retire in same timeframe.
   - Black & Veatch's December 2010 analysis stating that 52,000 MW of coal capacity would retire.
   - FBR, Capital Markets' expectation that 45,000 MW of coal capacity to retire by 2017.
   - BPC, March 2011 29-35 GW total retirements,
   - EEI, January 2011 46-56 GW total (24-34 GW incremental retirements)
   - CRA, December 2010, 39 GW total retirements
   - DOE, James Wood, deputy assistant secretary for the U.S. Department of Energy, comments at the Eastern Coal Council's Annual Conference May 2011, 30-75 GW

   These publications are significant because they show that in setting the Utility MACT standard the EPA has not adequately addressed the impact of the rule on the electric utility industry, given that costs are considerably more expensive for smaller units. This suggests that U. S. EPA modeling is subject to strong confirmation bias in favor of U. S. EPA's ideal outcome.

[49] http://www.epa.gov/ttn/atw/129/ciwi/fr21mr11.pdf

APPA believes that the U. S. EPA should acknowledge that the price per MW of compliance increases as the size of generating unit decreases.[50] This means that smaller generating units will be impacted more highly in their decision to comply with EPA's toxics rule. This disproportionately large impact poses a much more serious compliance hurdle for small communities that depend on coal fired generation to meet their base load demand. As can be seen in the excerpt from the Bernstein and EPRI data analysis in Exhibit 2 below, coal plant retrofits for SO_x control technology cost, on average, three times more per MW when performed on smaller generating units. In addition, the price of compliance doubles for NO_x control equipment as the size of the unit approaches 50 MW. **APPA believes that the EPA did not adequately consider the disproportionately large cost of compliance on small communities.**



Source: Bernstein Research coal plant SO_2 control retrofit analysis of capital cost by generating unit size

These disproportionately higher costs for smaller and medium-sized municipal utilities were missed by the U. S. EPA in its own technical and economic analysis. In addition, the U. S. EPA has missed the critical factor that cities are in a time of great financial stress due to falling tax revenue from fewer sales and declining property taxes. According to Meredith Whitney,[51] "While over the past 10 years state and local government spending has grown by 65%, tax receipts have grown by only 32%." Ms. Whitney's statement certainly confirms the hundred of press stories about municipal governments reporting lower tax receipts and layoffs. Some of the public power communities with electric utilities have also faced significant declines in property taxes and sales tax receipts.

8. APPA believes that the U. S. EPA's estimate of benefits and costs resulting from this proposed rule exaggerate the human health benefits dramatically because of its inclusion of $PM^{2.5}$. **Additionally, APPA believes that the costs were underestimated by not including many smaller utilities in the sampling or ICR run.**

9. APPA believes that the MACT new source limits were unrealistic and miscalculated based upon contractor errors (See UARG letter to U. S. EPA, dated May 6, 2011 in Appendix I.) **While APPA is pleased that the EPA has corrected, by letter, the new unit emissions, APPA notes that the EPA has not corrected all errors found in the proposed rule**. Such errors make it all the more risky for a utility to make business decisions now based upon a proposed rule.

10. APPA believes the U. S. EPA should be commended for using work practices in lieu of CO limits but we do ask EPA to consider UARG's technical comments. APPA recommends that

[50] U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?, BernsteinResearch, 2010
[51] "The Hidden State Financial Crisis," Wall Street Journal online publication, May 18, 2011

the rule includes an alternate surrogate CO limit for additional compliance demonstration flexibility. A surrogate CO limit [if set at a reasonable level (i.e., 0.25 lbs/MBtu)] to demonstrate dioxin/furan best combustion control practices might be easier for EGUs with pre-existing CO limits.

11. **The U. S. EPA did not adequately set subcategories for HCl, coal rank, and for rural and isolated power plants that may not have equal options for fuel. APPA also believes that ≤100 MW and peaking or limited use of (<30% annual capacity factor) units should have a separate subcategory**.

12. The U. S. EPA did not adequately study the costs to the electric utility sector resulting from inability to sell or trade coal ash/coal combustions residuals due to sodium content in ash from DSI control technology. (See narrative and table 3 on pages 74-77 for details)

13. Though the U. S. EPA states that Regional Transmission Organizations (or RTOs) should "consider the full range of options to provide any necessary power replacement," it is not reasonable to expect that the RTOs can produce the necessary engineering studies to determine the impact of U. S. EPA's rulemaking in the time allotted for comment. Nor is it reasonable to suspect that any remediation that might be required can be completed in time to allow units to retire.

    For example, NERC standard FAC-013-2 states that a Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). That includes a description of how each of the following assumptions and criteria used in performing the assessment are addressed, generation dispatch, including but not limited to long-term planned outages, additions and retirements. This assessment, along with all of the many other assessments and studies, take time to perform. A study on a single retirement or a few retirements might be possible, but many retirements grouped into a few month span would certainly be difficult. A review of the generator retirement section of the PJM website shows that there are a number of problems that must be addressed before a generator can be successfully retired.

    > "Generator retirements alter power flows that often yield transmission line overloads. From a Regional Transmission Expansion Plan (RTEP) perspective, generation retirements announced coupled with steady load growth and sluggish generation additions can lead to the emergence of reliability criteria violations in many areas of PJM. Generating unit deactivations can contribute to the need for future, long-term baseline reliability transmission upgrades to mitigate reliability criteria violations."[52]

    An analysis of the time it takes the PJM to respond to a generator request to shut down shows that without reliability issues they are able to remove a facility from the system within months.[53] However, if multiple units are forced to shut down due to this rule it could cause problems with multiple impacts. Where a system is in need of generation at a location multiple retirements will cause significant delays and 'reliability must run' agreements might be needed. Some problems that might occur from multiple forced retirements or from significant downtime as a majority of the existing fleet upgrades to environmental control technology, include, but are not limited to:

[52] http://pjm.com/planning/generation-retirements.aspx
[53] http://pjm.com/planning/generation-retirements/~/media/planning/gen-retire/generator-deactivations.ashx

- N-1-1 Thermal Violations,
- Generation Deliverability Violations,
- Common Mode N-1 Contingency Thermal Study Violations,
- Common Mode N-1 Contingency Voltage Study Violations,
- CETO Voltage Study Violations,
- N-1-1 Voltage Study Violations,
- Short Circuit violations

APPA would like to note that the Texas Reliability Entity filed a report with the Texas PUC, documenting a major outage during the February 2-3, 2011 timeframe.[54] This outage was extended by a lack of generator response during a cold weather event. This event is a chilling reminder that having generation offline for upgrades even during a low load season has its risks. **APPA is concerned that EPA has not factored in these types of contingencies when it developed this final rule**.

FERC and NERC are working together on an event analysis report detailing their conclusions and recommendations on the Texas generation failures. Their report is due out shortly. APPA will put a place holder in the appendices of these comments so that the FERC/NERC report may be given as additional materials. APPA will forward a copy of this report to the EPA docket when it is released. Since the report will be important in understanding the implications of reduced electric supply diversity, APPA feels the U. S. EPA needs to consider this report in this rulemaking.

NERC has filed with FERC a revision to its Critical Infrastructure Protection (CIP) Standards that may have bearing on the implementation of the U. S. EPA final rule. On February 10, 2011 NERC submitted to FERC a revision to NERC Reliability Standard CIP-002-4.[55] This revision will designate approximately 400 additional generating units under the CIP standards for compliance with cyber security requirements.

- Generation greater than 1,500 MW (59 using CIP-002-3, 229 using this criterion) - 170 additional units
- Blackstart resource identified in a transmission operator's restoration plan: (337 using CIP-002-3, 540 using this criterion) - 203 additional units
- Each generation facility necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon. (14 using CIP-002-3, 44 using this criterion) - 30 additional units
- Pending FERC approval, the anticipated affective date for compliance with this revised standard is 2013.

APPA is concerned that these 400 newly designated critical generation facilities will be evaluated for protection and compliance with NERC Reliability Standards at approximately the same time as the EPA final rule.[56] **APPA believes U. S. EPA should provide additional compliance options or a subcategory for units newly designated as critical under the NERC Reliability**

[54] http://www.puc.state.tx.us/agency/topic_files/TX_RE_EEA_Protocol_Comp_Report.pdf
[55] http://www.nerc.com/files/Final_Final_CIP_V4_Petition_20110210.pdf

[56] Critical Asset: Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System. http://www.nerc.com/files/Reliability_Standards_Complete_Set.pdf

Standard CIP-002-4. Some of these newly designated units also may decide to shut down due to the crush of all these competing regulations, and APPA believes that U. S. EPA should provide additional time for studies to determine the reliability impacts of these retirements.

The list of newly identified critical assets will not be available as a public document due to the assets being classified as critical and protected under FERC's CEII requirement and the DHS PCII requirement.

1. Department of Homeland Security Procedures for handling Protected Critical Infrastructure Information (PCII); Final Rule September 1, 2006: http://www.dhs.gov/xlibrary/assets/pcii_final_rule_federal_register9-1-06-2.pdf

2. FERC Critical Energy Infrastructure Information (CEII) http://www.ferc.gov/help/filing-guide/file-ceii/ceii-guidelines.asp#skipnav

APPA would also like to note that current proposed NERC Critical Infrastructure Protection standards will create an additional cost that was not considered in the EPA's economic analysis. This cost may be significant and should have been considered as a part of EPA's RIA.

An additional consideration is the availability of reciprocating internal combustion engines (RICE) units to soften the blow that the large scale scheduling of outages and retirement of plants will likely cause. APPA has already commented on and requested reconsideration for the U. S. EPA's RICE rule. We hope that the considerations will be resolved in time to allow RICE use and that U. S. EPA will allow emergency operation of these engines to help ease the transition pains that will be experienced by utilities as a result of this rule.

14. The **EPA did not properly and thoroughly investigate and address the significant cost imposed on all businesses that consume electricity by this proposed rule, therefore it should attempt to address the unproductive costs of compliance that will occur due to RTO market structures. Since this rule will, by EPA's own estimates, force the closure of many power plants that are often dispatched to meet demand (ie. the plants are determined to be efficient by the market mechanism), there will exist a higher probability for the dispatch of less efficient plants.**

Any generator facing an increase in the cost to produce a megawatt-hour of electricity will increase their offer to sell electricity by at least a corresponding amount.[57] This will include not only coal plants but also natural gas plants whose operating costs reflect increases in natural gas prices. **Because the highest offer accepted in an hour sets the price for <u>all megawatt-hours consumed</u>, a single coal or natural gas plant can affect the prices paid for by all the electricity generated by nuclear, hydropower, wind, and all other plants within that hour**.

Power generated by plants that do <u>not</u> face any greater compliance costs will therefore still be sold at a price reflecting at least the compliance costs paid by other plants. RTO markets therefore create an entirely separate category of "unproductive costs" on top of the actual compliance costs (also referred to by economists as "economic rent" or the amount paid above what is needed to keep a good or service in supply.) (See Section 15 for further explanations about electricity markets and the relationship of those markets to the costs that would be incurred by electricity consumers resulting from this rule.) APPA believes that the U. S. EPA

[57] Because there is no cost-based regulation of wholesale power prices, generators can offer to sell a megawatt-hour at a price that is greater or less than the actual costs of producing that power.

made no attempt to consider these market issues when assessing the costs of this rulemaking despite the fact that APPA met with U. S. EPA's chief EGU MACT and policy experts.

15. The RTO market structures are less likely to lead to the construction of new units that U. S. EPA states will be needed to meet demand, and will also contribute to a greater level of plant closures than in other regions. Moreover, the capital costs of retrofits to existing plants will cause significant extra costs for consumers within RTO regions because the market structure will multiply these costs beyond just the actual compliance costs. For example, in the most recent Reliability Pricing Model (or RPM) auction, held in May 2011 to procure capacity for the June 2014 through May 2015 time period, a number of plants added to their supply offers the costs associated with installation of emission control technologies to meet environmental regulations. PJM estimated that these higher costs were responsible for **at least half of the 350 percent price increase between the past two auctions in the western region of PJM**, from **$27.73 per MW/day to $125.99 per MW/day**. Although the number of units or MWs that included these compliance costs is not yet available, PJM's graphical representation shows that of the roughly 150,000 MW that cleared the auction and will receive this capacity price, about 120,000 MW offered to sell capacity at a zero or close to zero price. (Zero price offers are typically submitted by existing baseload plants who are price takers in the auction.) **Therefore the half of the $98 price increase attributable to environmental upgrades will be paid to all 120,000 MWs of capacity that did not include environmental compliance costs in their offers, equal to an unproductive cost of at least $2.1 billion for just one year.** The U. S. EPA did not seem to capture the impact of these auctions in its cost analysis.

APPA points out that the U. S. EPA's own economic modeling relies on per unit compliance costs only and does not appear to have taken the multiplier effect of the RTO market structure into account, even though these markets will greatly expand the actual cost to consumers. **These factual PJM auction results from May 2011 demonstrate that the U.S. EPA's assertion that the electricity consumer will see no more than a 3.6% increase in the cost of electricity does not match recent actual market performance.** The U. S. Census reports that currently there are 307,006,550 people in the United States and approximately **51 million of them live in the PJM Market**. This means that approximately 15% of the United States population is affected by PJM Market and any U. S. EPA regulatory factors that cause an increase in capital expenditures. APPA believes it is significant that the U. S. EPA does not seem to account for the impacts of this market its projected cost analysis. For more detailed information on electricity markets, reference Appendix J (APPA's *Neophytes Guide to Electricity Markets*) and Appendix K (*Why New CO_2 Regulations Could Produce Windfall Profits and Unproductive Costs for Consumers*).

16. The EPA did not adequately consider the distinctly large regional cost impacts of their proposed rule. Figure 4 exemplifies how coal plant closures will have a much more severe impact in different locations. Figure 5 presents a clear picture of how prices will increase due to the combination of the U. S. EPA's Transport Rule and MACT Rule. These projected price increases disproportionately impact coal-dependant regions of the U. S.

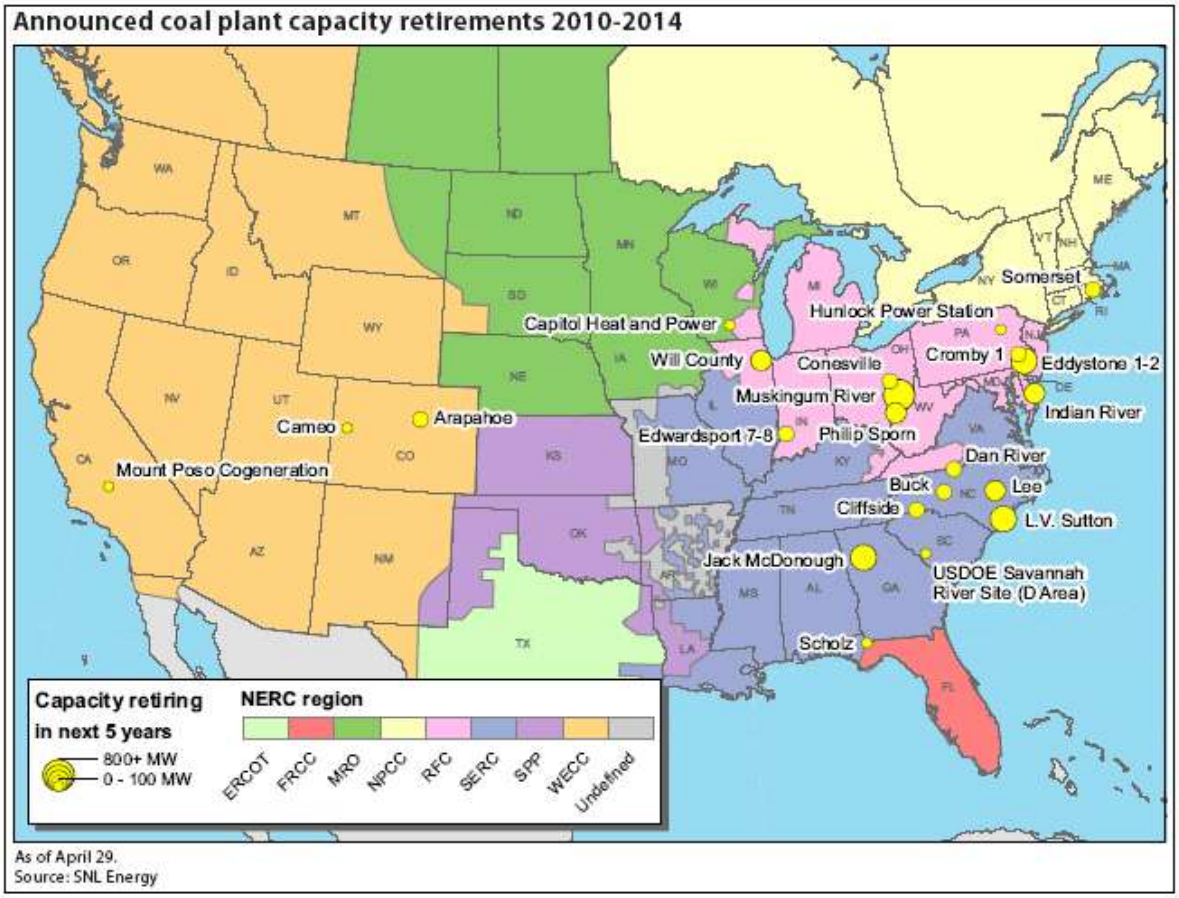


Figure 4: Source - Data Dispatch, Feb. 22, 2011 (Used with permission from SNL Energy) See Appendix L for more details.

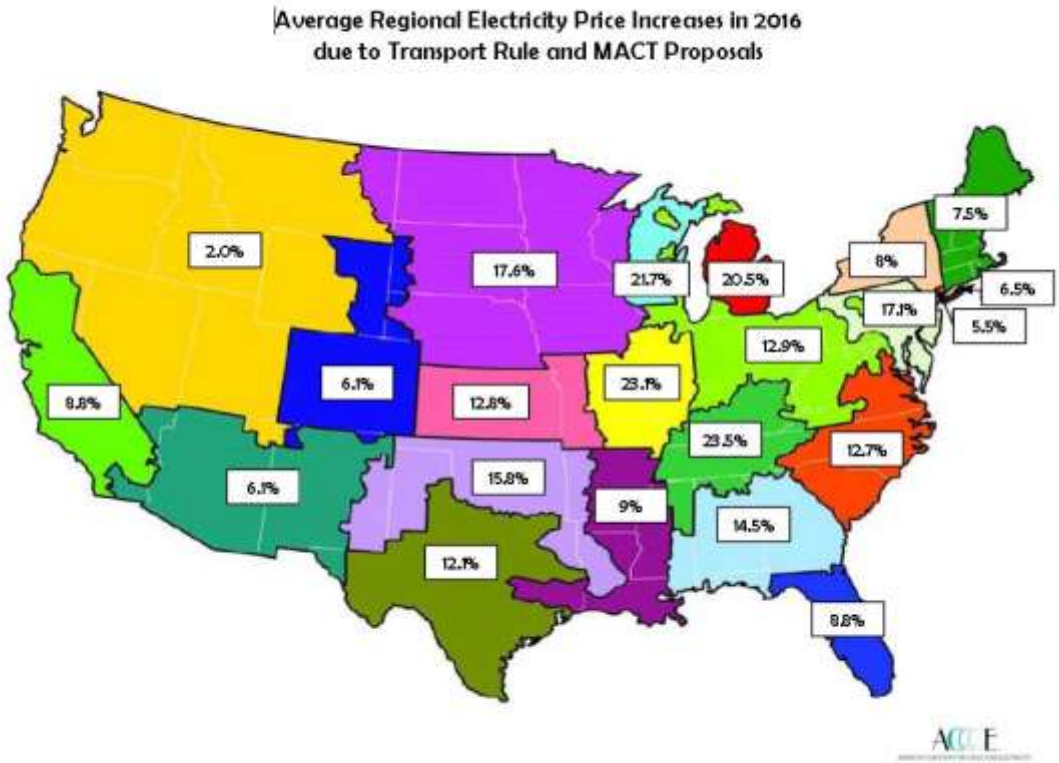


Figure 5: Source – American Coalition for Clean Coal Electricity. **Note:** Price increase does not include RTO electricity market price increase.

17. U. S. EPA did not properly assess the reliability issues related to the transformation of the industry through both fuel switching to natural gas or retrofitting a significant number of power plants within three years. APPA has pointed out our concerns with getting pollution control equipment designed, procured, financed, installed and calibrated and in place in the three year compliance deadline.

18. The U. S. EPA has some limitations placed upon it under the Clean Air Act that require a presidential extension of an additional year to be based upon national security concerns. In this instance, APPA assumes that national security would mean a significant concern about the reliability of the electric grid nationwide. APPA does <u>not</u> believe that there is a risk to the reliability of the entire <u>national</u> electricity infrastructure. APPA believes that the municipal utility sector (and perhaps some co-ops and IOUs) needs at least 5.5 years and perhaps as long as 77 months for planning, procuring, construction, installation, and calibration. APPA believes the presidential extension should be allowed on a utility-by-utility or case-by-case basis. This extension could be part of the time-constrained categorical extension talked about on page 62.

If the U. S. EPA fails to take the recommended actions to reduce the regulatory burdens of complying with the proposed MACT standards, APPA thinks it is critical for EPA to provide in the final rule for automatic compliance extensions to enable utilities, and particularly public power utilities to comply with the standard because of unique governmental administrative procedures that they must adhere to whether they retrofit or repower boilers. In this same vein, APPA observes that the Clean Air Act provides that the President has the authority under Section 112(i) of the Act to exempt any stationary source from compliance with any standard or limitation for a period of not more than two years if the President determines that the technology to implement the standard is not available and that it is in the national security interests of the United States to do so. The law also provides that such exemptions may be extended for one or more additional periods, each period not to exceed two years. 42 U.S.C. §7412(i)(4).

19. U. S. EPA failed to adequately and properly assess the feasibility and cost impacts of fuel switching from coal to natural gas. APPA urges the U. S. EPA to seriously consider the infrastructure (pipeline and natural gas storage) issues and other concerns found in the APPA study *Implications of Greater Reliance on Natural Gas for Electricity Generation*, which can be found in Appendix M. APPA also suggests that the U. S. EPA staff evaluate the most recent articles regarding natural gas supply resulting from the June 2011 *New York Times* stories.[58]

20. U. S. EPA has failed to anticipate additional costs from closure of coal-fired power plants in the PJM and other RTO markets where fuel switching to natural gas and early retirement without replacement of other units would result in substantially and disproportionately higher costs for millions of consumers.[59]

21. The U. S. EPA proposes in its rule that this rule will have a positive effect upon unemployment.

While APPA is not an expert on macro economic analysis on jobs, we are aware of the assertions of jobs to be lost on a state-by-state basis. The American Coalition for Clean Coal Electricity (ACCCE) took the EGU MACT proposed rule and the soon to be final Regional Transport Rule and determined that unemployment impacts far exceed the temporary jobs created under the U. S. EPA analysis. The ACCCE analysis will be submitted by the American Coalition for Clean Coal Electricity (Source: www.cleancoalusa.org). This organization projects net nationwide employment losses (employment losses minus employment gains) totaling 1.44 million job years by 2020. Employment sector losses outnumber gains by more than four to one through 2020 due to the two rules. By contrast, U. S.EPA's analysis of employment for the MACT proposal says that, "We expect that the rule's impact on employment will be small, but will (on net) result in an increase in employment." The U. S. EPA estimates a one-time increase of almost 31,000 construction jobs and an annual increase of 9,000 jobs in the electric sector.

22. U. S. EPA should not include start up, shut down and malfunction in its proposed standards. This would render the proposed standards inherently tighter than they appear on paper considering the time per year of start ups, shut downs and malfunctions. This is especially a concern because of the increasing number of "load-following" coal-fired power plants backing up wind and solar power plants. The ramping up

[58] http://www.publicpower.org/files/PDFs/ImplicationsOfGreaterRelianceOnNGforElectricityGeneration.pdf
[59] http://www.publicpower.org/files/PDFs/IssueBriefWindfallProfitsandEPARegsMarch2011.pdf

and down as well as the start up or shut down activities will increase emissions of many pollutants.

23. **U. S. EPA Should Provide for Streamlined NSR Procedures in the Final MACT Rule.** It is quite likely that modification of facilities to meet MACT standards, if they remain at or near to the levels proposed (in addition to modification of facilities to meet the Cross State Air Pollution Rule and New Source Performance Standards), could result in emission increases in one or more pollutants subject to the regulation under the federal New Source Review/Prevention of Significant Deterioration Clean Air Act preconstruction program or state "minor NSR programs" administered through federally enforceable state implementation plans (SIPs). We anticipate increases are most likely to result from pollution control changes that will produce increases in carbon monoxide, greenhouse gases, and/or nitrogen oxide from power to operate pollution control equipment or new natural gas-related equipment. As the U. S. EPA is aware, a Federal Court of Appeals held in *New York v. EPA, New York v. EPA, 413 F.3d. 3* (D.C. Cir. 2005) stated that pollution control projects are subject to New Source Review like any other plant modification. Because preconstruction permitting under the PSD/NSR takes between 14 months-to-5 years to complete, and generally with respect to electric generating units of any kind, engenders permit objections, it would be beneficial for U. S. EPA to streamline NSR procedures to the greatest extent provided by law. This could be accomplished by general permits that states could adopt now, a FIP for NSR permits for MACT, and/or schedules for expediting the receipt, determination of permit completeness (with a checklist) and release for public comment of PSD/NSR applications. <u>Failure to address the possible delays from PSD/NSR permitting in this rulemaking could add additional time for sources to operate in compliance with the final regulation</u>.

24. **APPA Members Experience Unique Issues with Respect to Complying with the Proposed MACT Standard for Existing Units, Particularly If U. S. EPA Fails To Take the Recommended Actions To Reduce the Regulatory Burdens of Complying with the Proposed MACT.**

    Section 112(d)(4) of the Act provides that the Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory (of an industrial sector) in establishing MACT standards. We acknowledge that this ability to subcategorize, which U. S. EPA has already used to subdivide the industry sector by type of fuel and size, shall not be used under Section 112 (d)(1) for purposes of authorizing extensions. However, we believe that U. S. EPA has authority to use its discretion to establish emission limits for types of sources, based on ownership and location, that it has not recognized and can address some of the unique issues that not-for-profit utilities face, including but not limited to the ownership, size of communities served, and most importantly, location. We suggest that U. S. EPA must examine these issues carefully and determine standards based on the criteria enumerated in Sections 112(d)(2) and (d)(3) for these sources.

    As APPA's comments have already described, the majority of public power generators are small entities as defined by federal law. They are all not-for-profit. Seventy percent of public power systems are located in cities with populations of 10,000 or less, and a significant percentage of these systems are located in rural locations, including Alaska, Guam, Puerto Rico and American Samoa. In cities and townships, electric generation is generally located in the center of town, bounded by railroad easements and private property. These characteristics of our members' operations have several significant consequences for public

power and rural electric cooperatives that will make compliance with the proposed standards uniquely difficult:

(1) Many municipal utilities are space-constrained and cannot build laterally. They must build vertically, but this makes construction of dry scrubbers, ESPs and fabric filters technically infeasible. If the U. S. EPA were to examine the group of facilities as a subcategory, it is likely that the agency would set a different floor for this subcategory of utility.

(2) Most of these facilities have only two boilers and possibly off-site gas turbines for peaking. Quite a few also own wind and/or solar generation that provides an interruptible power supply. As a consequence of state and federal requirements these operators can take only one unit off-line at a time for refurbishment and retrofit or repowering.

(3) These communities are generally not located near natural gas pipelines, except in the southwest and isolated areas in the northeast. As a consequence of their size, infrastructure is not likely to come to them so that they can avail themselves by repowering units.

APPA submits that U. S. EPA has ignored these significant distinctions and the level of controls that are and can be achieved by these distinct parts of the utility industry. In part, this is a result of inadequate scoping and review under the Unfunded Mandates Reform Act (UMRA) and SBREFA, discussed earlier in these comments. On this basis, we urge the U. S. EPA to re-propose the MACT rule to reexamine not only the regulation of pollutants other than mercury, but to reexamine the subcategorization of the industry by ownership and location. If this examination is done properly, the MACT floor for units based on their footprint and location will be vastly different than the level of emissions control achieved for larger non-rural power plants.

APPA's Technical Comments on the Proposed Rules

I. Rulemaking Background

A. U. S. EPA has rushed its own regulatory schedule and is under no court order. APPA believes it is simply not true that the U. S. EPA must propose/finalize the MACT rule as quickly as suggested in the proposal. APPA believes the judge who presided over the consent decree for proposal and timing made it clear that the U. S. EPA would be given more time if technical or scientific issues necessitated it.

II. The Clean Air Act

A. APPA defers to the UARG letter on the legal and policy issues related to the various Clean Air Act programs, including the interplay of NSPS, NAAQS, PSD (BACT) and nonattainment programs, such as Lowest Available Emissions Rate (LAER), and how the EPA has confused these discreet regulatory programs and tried to insert into the proposed EGU MACT rule ways to reduce $PM^{2.5}$ etc. APPA believes that the U. S. EPA has exaggerated the health and economic benefits of the proposed rulemaking by asserting benefits from $PM^{2.5}$ controls and from control of other pollutants, such as acid gases.

APPA believes that the U. S. EPA should address PM only under ambient standards that are set to protect human health under an adequate margin of safety. That is to say, since $PM^{2.5}$ is a criteria pollutant, it has no place in a regulatory schema for HAPs, even as a co-beneficiary.

Any PM emission limitations should be justified within the context of PM regulatory programs. Similarly, reductions of HAP compounds – those specifically listed by Congress in the Act – should stand on their own merits as well.

B. The Clean Air Act's utility study [and U. S. EPA's related Great Waters Study along with assessment of the Section 303(d) waterbody segments listing of noncompliant waterbodies in the Clean Water Act,] **justified only mercury reduction through the MACT program**. U. S. EPA's own utility study said "*The report indicates that, although uncertainties in the analysis exist, on balance, mercury from coal-fired utilities is the hazardous air pollutant of greatest potential public health concern."* The U. S. EPA's utility study did not justify additional acid gas controls, PM $^{2.5}$ controls or other controls through new NSPS regulations.
See U. S. EPA's Source: http://www.epa.gov/ttncaaa1/t3/reports/utilfs.pdf **APPA strongly believes that the U. S. EPA far exceeded its statutory authority to propose MACT for non-mercury metals and acid gases**. (See Section IV below)

C. As a member of UARG, APPA defers to the legal analysis and critique of Section 111, including discussion of subcategorization, factors that must be analyzed (degree of emissions reduction achievable, cost, non-air quality health and environmental impact, energy requirements, adequate demonstration of technology).

III. General Policy Considerations

A. Effects on economy of making it difficult or impossible to permit or build a new coal-fired power plant.
B. Problems associated with essentially mandating certain technologies or making certain technologies are obsolete.
C. The U. S. EPA has utilized its statutory authority to propose area source controls (GACT) for the power sector. These GACT controls would be less expensive than the control technologies in the proposed rule for many pollutants. The U. S. EPA failed to avail itself of its ability to use GACT controls and subcategorize adequately to help either the smaller utilities or the larger utilities.

GACT controls have been used successfully in many other U. S. EPA MACT rules including the following industries:

- Iron & Steel Foundries
- Electric Arc Steelmaking
- Coatings Operations Area Source Controls Rule
- Clay Ceramics Manufacturing
- Glass Manufacturing
- Secondary Nonferrous Metals Manufacturing
- Paint Stripping & Miscellaneous

IV. U. S. EPA's Proposed Particulate Matter NSPS (APPA defers to UARG on the legal analysis and policy comments on the NSPS.)

A. Background

1. New and reconstructed boilers**. The current NSPS allows three ways to comply:**

(1) 0.015 lb/MBtu; (2) 0.14 lb/MWh (24-hr average); or (3) 0.03 lb/MBtu and a 99.9% reduction.

a. The U. S. EPA proposed a total PM NSPS of 7.0 ng/J or 0.055 lb/MW-hr (0.006 lb/MBtu). PDF, p. 655. The limit is proposed to be a summation of Method 5 (filterable PM) plus Method 202 (condensable PM) and includes periods of startup/shutdown/malfunction. PDF, see pg. 487-88 of the pre-publication version of the proposed EGU rule.
b. The U. S. EPA is considering a range between 15 ng/J to 5.0 ng/J (0.004 - 0.034 lb/MBtu) for the final rule.

2. Modified boilers**.**

The current NSPS requires achieving 0.03 lb/MBtu and a 99.8% reduction.

a. The U. S. EPA proposed a limit of 15 ng/J (0.034 lb/MMBtu).
b. This is more stringent than the proposed limit for new units, and is likely an error. The U. S. EPA erred in the proposed regulatory language (§ 60.42Da (f)(2)) for modified units. The proposed limit of 0.034 lb/MMBtu could possibly be 0.13 lb/MBtu and was converted incorrectly from 15 ng/J. Alternatively; the limit of 15 ng/J was converted incorrectly from 0.034 lb/MMBtu.

B. U. S. EPA Should Rescind Its Proposal and Repropose its Defective NSPS Rule

1. U. S. EPA misstated the limit for modified boilers. The regulated community cannot provide intelligent comment on the agency's proposal and therefore the U. S. EPA should rescind its proposal and repropose the rule after correcting these defects.

C. U. S. EPA's Choice of Best Demonstrated Technology Is Contrary to Law

APPA defers to UARG in the more thorough analysis and critique of the EPA's choice in combining technologies to define Best Demonstrated Technology (BDT).

1. U. S. EPA may <u>not</u> require a combination of technologies to be BDT.
   a. U. S. EPA based its NSPS for new and reconstructed units on a combination of four technologies -- **fabric filters, FGD, dry sorbent injection and wet ESPs**. The Agency based its NSPS for modified units on a combination of FGD and fabric filters.
   b. The "best system of emission reduction" under §111(a)(1) does not allow U. S. EPA to base the NSPS on a combination of technologies and EPA has not attempted to do so in the past.

D. U. S. EPA erred in not calculating correctly in settings its preferred Best Demonstrated Technology.

APPA defers to UARG's more thorough comments addressing the failure to calculate properly in setting the Preferred Best Demonstrated Technology.

1. U. S. EPA claims the NSPS are "cost free" because the proposed PM NESHAP limits for new units are as stringent or more stringent. Yet §111(a)(1) requires EPA to "tak[e] into consideration the <u>cost</u> of achieving such reduction . . . ."
2. The cost of adding, e.g., a wet ESP or dry sorbent injection after a new unit has installed fabric filters and FGD is likely so expensive that the gency's BDT is arbitrary and capricious. APPA defers to the analysis provided by UARG on costs of this selection of technologies making up BDT. That analysis is provided in UARG's comments or appendices.

3. The cost of adding a fabric filter or FDG to a modified unit that has ESPs but does not already have an installed fabric filter or FDG is likely so expensive that the Agency's BDT is arbitrary and capricious. APPA defers to the technical analysis and cost materials provided by UARG in their separate comments.
4.(a)EPA has not identified what the condensable is and how to control it, so the agency cannot identify BDT or set an NSPS. (b) EPA's proposed rule **eliminates** ESPs as a control option.
    1. APPA defers to UARG's more detailed comments regarding technical work to be completed both for new (proposed as 0.006 lb/MBtu) and for modified units.
    2. APPA defers to UARG regarding U. S. EPA's option that ESPs should be retained as a control option.

E. APPA agrees with UARG that the U. S. EPA's proposed NSPS is not achievable

1. Analysis is provided in the detailed comments to explain that the U. S. EPA used the top 20th percentile of performance test data because no one is "specifically attempting to control condensable PM beyond eliminating the visible blue plume." In addition, EPA seems to have changed its method to calculate achievability.

2. APPA defers to the UARG analysis and agrees that this shows that limits lower than the proposed NSPS are **<u>not</u>** achievable.

3. U.S. EPA used the entire population of ICR PM data as its basis to propose NSPS. The data for these units differ from those employed for SO_2 and NO_x in that most data sets are limited to three independent, discrete measurements. A significant challenge in using data from these reference units is properly accounting for variability due to both unit operation and measurement capability.[60]

   U. S. EPA's methodology for proposing its Total PM NSPS of 0.055 lb/MWh for new and reconstructed units is unclear. The "BDT" selected by U.S. EPA for Total PM -- a combination of a fabric filter with coated or membrane filter media bags, FGD, dry sorbent injection (DSI) and a wet ESP -- has been installed at a single coal-fired unit (Dallman Unit 4).[61] It appears that U. S. EPA has arbitrarily selected the top 20th percentile of performance test data on the basis that no one is "specifically attempting to control condensable PM beyond eliminating the visible blue plume." 76 Fed. Reg. at 25,064, col. 3. In addition, the variability "analysis" for the agency's proposed Total PM standard appears to be based on an assessment of data obtained from a single facility (J. K. Spruce) without any attempt to evaluate the national boiler population with respect to variability in fuel, plant operation, age and other key variables.[62]

   UARG provided U. S. EPA in January 2011 with an analysis based on the ICR data concerning a filterable PM rate that can be achieved by both a fabric filter and a well-performing ESP at new units.[63] APPA agrees with this analysis. Starting with an average emission rate of 0.011 lb/MMBtu and factoring in the variability for this type

[60] *Id.* at Section 4.
[61] *Id.* In addition, wet ESPs are operating on only two units in addition to Dallman, one of which has a design that is very different from conventional designs for utility boilers. *Id.*
[62] *Id.*
[63] *Id.* at Figure 4-1, reproduces data submitted in the January 2011 paper.

of measurement, **a filterable value of 0.015 lb/MMBtu should be used** – the same as the 2006 NSPS.[64]

With respect to modified units, U. S. EPA states the Total PM value of 0.034 lb/MMBtu represents no real adjustment or change to control technology deployment compared to the 2006 NSPS. However, U. S. EPA's proposed Total PM limit is not limited to filterable PM and includes condensable PM. U. S. EPA has provided no data to suggest that the 2006 NSPS, which allows compliance by achieving both 0.03 lb/MMBtu and a 99.8% reduction, can be improved.

V. Proposed Revisions to SO_2 NSPS

A. Background

1. **New and reconstructed** boilers. For most units, the current NSPS is 1.4 lb/MWh (0.16 lb/MBtu) or a 95% reduction.
    a. U. S. EPA proposed 1.0 lb/MWh (0.11 lb/MBtu) (30-day roll) or a 97% reduction. PDF, p. 504. The NSPS includes periods of startup, shutdown and malfunction. PDF, pp. 487-88 of pre-publication copy.

    b. U. S. EPA is considering a range between 0.80 – 1.2 lb/MWh and a percentage reduction between 96–98% for the final rule.

2. **Modified and new coal refuse units**. U. S. EPA proposes retaining the current NSPS.
    a. APPA believes that UARG has better expertise on U. S EPA's assertion that they should preserve the ability to use spray dryer FGDs for modified units. APPA defers to UARG's comments.

B. APPA believes that the U. S. EPA should rescind its proposal and repropose its defective NSPS rule

1. It is unclear to APPA in the proposal what technology U. S. EPA considers to be best demonstrated technology. For the fixed emission rate it may be dry FGD. The U. S. EPA does not clearly state the technology on which it bases its percentage reduction standard. The U. S. EPA rushed the proposed rule process without sufficient time to propose a coherent rule and intends to finalize it in November 2011 without sufficient time to correct the defects in the proposal. **APPA points to this as one of many data errors that resulted from too short of a preparation time and an improperly designed schedule for proposal and final rule.**

2. Without knowing BDT, the regulated community cannot provide intelligent comment on whether the emission limits are achievable or whether the costs of the technology are reasonable under § 111(a)(1). **APPA believes that the U. S. EPA should rescind its proposal and re-propose the rule after correcting these defects in its proposed rule**. APPA does not believe it is realistic for local governments to commit to purchasing control technology equipment, finance, permit, install and calibrate within three years given local governance rules on procedure and current economic problems.

[64] *Id.*

C. EPA erred in not calculating a cost for its preferred Best Demonstrated Technology

1. The U. S. EPA claims the NSPS are "cost free" because the proposed SO_2 NESHAP limits for new units are as stringent or more stringent. (PDF, pp. 538-39 of pre-proposed rule.) Yet § 111(a)(1) requires EPA to "tak[e] into consideration the cost of achieving such reduction . . . ."
2. The U. S. EPA failed to do any cost analysis, so the proposed rule is arbitrary and capricious.

D. The Proposed NSPS Are Not Achievable

1. APPA reminds the U. S. EPA that UARG provided comments in January, 2011 on what could constitute NSPS. A link to those UARG comments is http://www.publicpower.org/files/PDFs/UARGSCR_FGDFinal.pdf and a copy of this set of comments (in a study) is attached in Appendix F.

   APPA reminds the U. S. EPA that in UARG's analysis they analyzed similar units and found that achievable NSPS are 1.3 lb/MW-hr (0.14 lb/MBtu) with a 96% removal efficiency.

2. APPA agrees with UARG that the U. S. EPA's variability analysis of fixed rate data is not consistent with past rulemakings.

3. It is fundamental to the implementation of CAA § 111 that any NSPS must be achievable. *Portland Cement Ass'n v. Ruckelshaus,* 486 F.2d 375, 402 (D.C. Cir. 1973). An NSPS represents the best technology available nationwide, regardless of specific fuel, climate, water availability, and many other highly case-specific factors. As discussed below, U. S. EPA's proposed NSPS for SO_2 are **not** achievable on a nationwide basis, and the final rule needs to be revised upwards because the proposed rule is much too low.

   The UARG white paper submitted to U. S. EPA in January 2011 analyzed SO_2 emissions from representative units and concluded that combustion controls and FGD at 24 new units and 32 retrofitted units could achieve 1.3 lb/MW-h (0.14 lb/MMBtu) and a 96% removal efficiency.[65] To justify its proposed revisions to the NSPS for SO_2, U. S. EPA selected existing units that retrofit FGD technology and new units that integrate the FGD process design into the plant. Tables 17 and 18, 76 Fed. Reg, at 25,065. A disadvantage of utilizing only new units to evaluate SO_2 emissions is that both the control technologies and fuel represented are not representative of the fuels and conditions on a nationwide basis. The trend for newer units has been to locate them in western states, with improved access to PRB coal and perhaps less access to water. **This trend biases the selection of SO_2 controls at the newest units to lime-based dry FGD.**[66] **Analyzing both new and recent retrofits to existing units provides a broader spectrum of controls and fuels, and reflects the use of eastern bituminous coals and wet FGD.**

   As explained in detail in the report by Cichanowicz to the Utility Air Regulatory Group, of which APPA is a member, neither the eight new units that U. S. EPA

[65] Cichanowicz, Discussion of Factors Affecting New Source Performance Standards for SO_2, Particulate Matter, And NOx At Utility Steam Generating Units (January 2011).
[66] *Id*. at ___.

examines (Table 18) nor the 15 existing units that the Agency considers (Table 17) reflect the full suite of designs, fuels and conditions for the coal-fired boiler population in this nation.[67] The report can be found in Appendix N. One new unit (Spurlock Unit 3) has a fluidized bed design that is atypical of pulverized coal boilers and which inherently provides SO_2 removal through the limestone-containing bubbling bed. **Both the magnitude and variability of the SO_2 emissions from fluidized bed designs are unrepresentative of pulverized coal boilers and such units should either be eliminated from consideration or used in a separate subcategory for this boiler design**.

Five of the remaining new units are virtually identical in firing PRB coal and using lime-based dry FGD with a fabric filter. This combination of coal and equipment provides stable and well-controlled SO_2 emissions.[68] However, **it is inappropriate to set a standard for all new coal-fired boilers that is based on this single full/control technology combination**. Additionally, the final two new units (Cross Units 3 and 4) in U. S. EPA's database are virtually identical in design and both fire eastern bituminous coal with moderate sulfur content. Thus they provided only limited information about non-PRB units. There are similar problems with the existing units.[69] **APPA urges U. S. EPA to base its decision on the final NSPS using the larger and more comprehensive data set that it has available, and that was provided by UARG, including three new units not considered by U. S. EPA (Elm Road, Oak Grove and Dallman**).[70]

U. S. EPA's methodology in determining its proposed NSPS for SO_2 improperly accounts for variability. Table 17 reports for 15 units the highest 30-day SO_2 removal efficiency average based on daily averages of SO_2 emissions and monthly averages of coal sulfur content. As explained in detail in the Cichanowicz Report,[71] **U. S. EPA's SO_2 removal efficiency cannot be considered a 30-day rolling average but an amalgam of daily and monthly "block" averages.** Of the 15 units in Table 17, 10 report only 12 months of operation and thus provide only 12 truly discrete data points. **Under this approach, a standard is proposed that new units would only be able to meet 92.7% of the time for any one unit** – a threshold well below the usual 99% compliance rate historically used when setting NSPS. U. S. EPA has historically understood that achievability of any emission standard requires that there be an appropriate increment or "margin" above the mean emission level that takes into account the statistical properties of the emissions data and the time dependence (auto correlation) of the data. Among other things, the achievable emission limit is a function of the assumed accepted number of violations of the regulatory limit, which is a measure of the risk of noncompliance. **This means U. S. EPA's 97% SO_2 removal rate is at odds with U. S. EPA's historical methodology in NSPS rulemakings, and results in a proposed NSPS that is not achievable because there is a certainty that many units will regularly exceed the proposed NSPS.**

U. S. EPA's selection of a 1.0 lb/MWh emission rate is without any statistical basis and seems to have been selected as the mid-point between new facilities

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[67] *Id*. at ___.
[68] Weilert, C., et al., Emissions Control Performance Achieved in Electric Utility FGD Systems in the United States, Proceedings of the 2010 Power Plant Air Pollution Control "Mega" Symposium, August 30-September 2, 2010, Baltimore, MD.
[69] Cichanowicz Report, p. 58
[70] Cichanowicz Report, Table 2-1.
[71] *Id*. at __.

burning medium sulfur coals and several dry FGD, PRB-fired units.[72] Accordingly, two new generating units with advanced FGD that fire medium-sulfur coals (Cross Units 3 and 4) could not meet *either* the fixed SO_2 outlet rate *or* the percent SO_2 removal, a clear indication that U. S. EPA's proposed NSPS for SO_2 is not achievable. U. S. EPA should apply UARG's and EPA's historical approach to variability.

UARG has provided the 30–day SO_2 average for the new unit pool, based on calculations defining the 95% and 99% confidence limits for each of the subject units.[73] The resulting standards range in value from 0.029 lb/MMBtu to 0.223 lb/MMBtu, and average 0.119 lb/MMBtu. Given a typical new unit heat rate of 9,500 Btu/kWh, this translates into an output-based SO_2 emission rate – not accounting for emissions during startup - of **1.13 lb/MWh.** Similarly, 32 units that were used as the basis for a recent BACT analysis indicate that EPA's proposed NSPS, when subjected to a statistical procedure to derive a UCL for 99% confidence limit, should be 0.130 lb/MMBtu (equivalent to 1.2 lb/MWh), not 1.0 lb/MWh.

This discussion does not consider the fact that the U. S. EPA includes periods of startup in the proposed NSPS. **UARG has evaluated the effect of including startups for 14 units equipped with state-of-art wet limestone FGD process equipment. UARG learned that SO_2 emissions can increase the value of the first 30-day calculated rolling average, from 1% up to 16%, and by an average of 8%**. In one-third of the cases analyzed, the first calculated 30-day SO_2 emissions average was increased by 10% or more above the value that would be calculated in the absence of including startup data.[74] **SSM should be excluded or the values of SO_2 emission rates should be increased to at least 1.30 lb/MWh to account for SO_2 startup.** Otherwise, the U. S. EPA's proposed NSPS for SO_2 are not achievable as a national standard.

VI. Proposed Revisions to NO_x NSPS

A. Background

1. **New units**. The current NSPS is 1.0 lb/MWh. **Reconstructed units**. The current NSPS is either 1.0 lb/MWh or 0.11 lb/MMBtu. **Modified units**. The current NSPS is either 1.4 lb/MWh or 0.15 lb/MMBtu.
2. The U. S. EPA proposed a NO_x NSPS of 0.70 lb/MWh (based upn 30-day roll) for new, reconstructed and modified units. This includes periods of startup, shutdown and malfunction.
    a. The U. S. EPA is considering a range between 0.60 – 0.90 lb/MWh for the final rule. Best demonstrated technology is combustion controls plus SCR.
3. The U. S. EPA is also proposing its alternative and preferred approach for **new and reconstructed** boilers of 1.2 lb/MWh (0.13 lb/MBtu) for NO_x + CO
    a. This standard is derived from 0.08 lb/MBtu NO_x; 0.05 lb/MBtu CO (70 ppm @3% O_2)
4. The U. S. EPA is also proposing its alternative and preferred approach for **modified** boilers of 1.8 lb/MWh (0.20 lb/MBtu) for NO_x + CO

[72] *Id.* at __.
[73] *Id.* at Table 2-1.
[74] *Id.* at Table 2-2.

a. This is derived from 0.08 lb/MBtu NO_x; 0.12 lb/MBtu CO (160 ppm @3% O_2)

B. The Proposed NSPS Are Barely Achievable (Given Current Technologies)

APPA defers to UARG's analysis, provided to the U. S. EPA in a white paper in January 2011. UARG analyzed similar units and found the NSPS should be 0.7 lb/MWh. APPA believes that the final NSPS should be no lower than the U. S. EPA's proposal and that the final NSPS should be higher for modified units.

VII. U. S. EPA Should Use Gross Output, Not Net Output, to Set NSPS

U. S. EPA has proposed output-based NSPS for PM, SO_2 and NO_x based on gross energy output. 76 Fed. Reg. at 25,070, col. 3. Much of the parasitic power demands at coal-fired power plants is needed to operate control equipment such as SCR reactors, scrubbers and baghouses that are required as a practical matter at all new coal-fired units. EPA states that it prefers using a net-energy output basis for new and reconstructed units because such an approach purportedly would "provide a greater incentive for achieving overall energy efficiency and minimizing parasitic loads."

In its 2005 NSPS proposal, the U. S. EPA recognized "the monitoring difficulties in measuring net output." 70 Fed. Reg. 9706, 9713, col. 1 (February 28, 2005). This remains an issue today. Many utility plants are comprised of multiple units and typically individual units are dedicated to the operation of specific equipment throughout the plant.[75] These units may provide power for the air compressors for soot blowing in the plant, for the coal handling system, for induced and forced draft fans, or for plant service such as offices, station water, etc.[76] The distribution of electricity throughout a plant is fed from auxiliary station transformers and then is distributed to the various load centers for power-consuming auxiliaries.[77] Under a net output-based NSPS, it would be difficult, if not impossible, to account for the power distribution for a new unit at a site with existing units. The older units would not necessarily be equipped to monitor the power going to and coming from the new unit, as the new unit would require the power distribution systems to be monitored for the first time.[78]

U. S. EPA suggests that "about 5 percent of station power is used internally by parasitic energy demands, but these parasitic loads vary on a source-by-source basis." 76 Fed. Reg. at 25,070, col. 3. Parasitic energy demands not only vary by source but also by duty cycle. As load decreases on a typical unit, the percent of parasitic power increases.[79] Base-loaded units could take full advantage of the relatively low parasitic power losses at high loads but cycling or peaking units could not due to rapidly changing operating conditions and the fact that much of the time is spent at low loads.[80] **Any net output-based NSPS would have to be set at levels that are achievable under all potential operating duty cycles**.

However, U. S. EPA should reject the use of a net energy output approach. Coal-fired power plants that are required by U. S. EPA's rules to use equipment to control PM, SO_2 and NO_x should not be further penalized by subtracting the parasitic power to run them. There are also significant issues with a net output approach due to water issues. As Clean Water Act § 316(b)

[75] Memorandum from Lowell L. Smith to Craig S. Harrison, "Impact of Net Output-Based NSPS" (June 2011), Attachment 1 (hereinafter "Lowell Smith Memo").
[76] *Id*.
[77] *Id*.
[78] *Id*. If a new unit were to be constructed at a greenfield site, this would not be an issue.
[79] *Id*. at Figure 1
[80] *Id*.

regulations are implemented, power stations may be building more cooling towers, which would add significant parasitic load. Water processing and pumping activities can have a large parasitic load that varies widely among plants. Some plants would be unfairly penalized if they had to comply with a net-output based NSPS.

At plants with older, less efficient units that supply power to various auxiliaries throughout the plant, imposing a net output-based NSPS on the new unit could actually decrease overall plant efficiency. The new unit would likely be much more efficient than the older units. Under a net output approach, the newer unit might not be used to supply power to the plant's auxiliaries because it would affect its net output emission level and jeopardize meeting the NSPS.[81] **This would rob the entire plant of an efficient source of power that could be used to replace power from less efficient units.** U. S. EPA suggests that a net output NSPS would improve overall plant efficiency, but instead that approach could require a new unit to be operated as an island with virtually none of its power providing auxiliary support for other units. **By instituting a net energy output based NSPS, U.S. EPA would be encouraging new units that may prove to be efficient, but overall the plant efficiency would not be optimized**.

The U. S. EPA notes that a net output approach will be problematic with emerging technologies such as IGCC, but nonetheless makes a rough estimate that "the efficiencies are comparable." 76 Fed. Reg. at 25,071, col. 1. **Yet a net output-based NSPS would eliminate use of any technology that would cause the parasitic power on an EGU to marginally increase above its current levels. For example, carbon capture and sequestration ("CCS") may have a 25-30% parasitic power demand.**[82] U. S. EPA has been attempting to foster IGCC and CCS, and a net output energy approach would not encourage the deployment of these technologies. The notion that a net output energy approach would "provide a greater incentive for achieving overall energy efficiency and minimizing parasitic loads," *id*. at 25.070, col. 1, is misplaced. **APPA strongly disagrees that utilities need a CAA regulation or any additional motivation to generate electricity as efficiently as possible.** Public power utilities, due to their ownership structure, are already trying to maximize plant efficiency for the benefit of their customers.

Finally, the U. S. EPA has announced plans to propose NSPS for greenhouse gases ("GHG"), including existing and new units, by September 30, 2011. U. S. EPA's regulatory approach will likely focus on running coal-fired power plants as efficiently as possible. A GHG NSPS rulemaking would invalidate any rationale for requiring a net efficiency approach in Subpart Da.

For these reasons, APPA strongly objects to requiring a net output approach.

A. EPA requested comment on this issue with respect to new and reconstructed units.

APPA defers to UARG's more detailed comments on errors in methods to set NSPS based upon Gross Output. EPA has previously used gross output and APPA (and UARG) believe that it should have been used here again.

B. APPA defers to UARG that separate units should not be penalized for parasitic power from the use of control technologies.

Such an approach would make NSPS especially stringent for coal (or natural gas fired) units that deploy geologic sequestration of CO_2 (or CCS). While APPA remains skeptical that CCS will be commercially demonstrated for widespread application in the utility sector within the

[81] *Id*.
[82] *Id*. at Figure 2

next decade, we certainly do not want to see the parasitic power issue make CCS less economical or attractive as a solution for CO_2 due to the unintended consequences that might result in the EGU MACT rulemaking.

VIII. IGCC Units Should Continue To Be Regulated Under Subpart Da, Not Subpart KKKK

A. The U. S. EPA proposes that IGCC units that coproduce hydrocarbons or hydrogen be subject to the combustion turbine NSPS because using new output-based standards would be difficult. APPA is unaware of any APPA member with current IGCC projects. We defer to UARG and EPRI in any submittals on data for proposed IGCC facilities.

IX. APPA endorses UARG's objection to adding petroleum coke to the definition of coal.

X. If U. S. EPA fails to take the recommended action to reduce the regulatory burdens of complying with the standards, the agency must provide compliance extensions to ensure that public power utilities can comply due to unique local governmental obligations to provide electricity to customers under law

XI. APPA Urges the U. S. EPA to Adopt Procedures for the Presidential Extension To Provide an Additional Two Years for Compliance.

If the U. S. EPA fails to take the recommended actions to reduce the regulatory burdens of complying with the proposed MACT standards, APPA thinks it is critical that the final rule provide automatic compliance extensions to enable utilities, and particularly public utilities, to comply with the standard. Public power utilities face unique governmental administrative procedures that they must adhere to whether they retrofit or repower boilers. In this same vein, APPA observes that the Clean Air Act gives the President authority under Section 112(i) of the Act to exempt any stationary source from compliance with any standard or limitation for a period of not more than two years if the President determines that the technology to implement such standard is not available and that it is in the national security interests of the United States to do so. The law also provides that such an extension may be extended for one or more additional periods, each period not to exceed two years. The Clean Air Act provides Section 112(i) that the President may exempt any stationary source from compliance with any standard or limitation for a period of not more than two years if the President determines that the technology to implement such standard is not available and that it is in the national security interests of the United States to do so. Such extension may be extended for more one or more additional periods, each period not to exceed two years. 42 U.S.C. §7412(i)(4).

APPA urges U. S. EPA to consider providing procedures for exercise of this Presidential option given the issues for public power operators we have described elsewhere in these comments, including but not limited to the administrative procedures for bidding contracts under municipal and state law, the eminent domain that some communities must exercise to access land for gas pipelines and/or transmission lines for new energy sources, issues with such public easements given the high density zoning in small municipalities, and general lack of electricity alternatives. These technical impediments to repowering and/or retrofitting publicly operated power plants and/or providing communities with electricity *transcend* technological and economic feasibility issues that APPA discusses elsewhere in these comments.

<u>Procedures</u> - We suggest that these procedures should involve requests from the mayor and the governor of each state for the proposed extension, with a demonstration of cause certified by the City Council or the State Attorney General and the entity requesting such extension. In other

words, APPA submits that these procedures should be based on need and the demonstration of good faith progress toward compliance, not Clean Air Act technology-based showings.

XII. Monitoring Issues (testing compliance and maintenance)

APPA fully supports UARG's comments on the emissions testing, compliance and reporting provisions in the proposed rule.

The proposed regulation would require installing up to three new monitoring devices in existing smokestacks. This would be in addition to at least three systems currently installed on these Title IV affected units[83]. EPA gives no impact evaluation on the safety issues surrounding drilling additional holes in existing stack and chimney liners. In the experience of one APPA member in the Midwest, following promulgation of the CAMR regulation, that utility had considerable difficulty finding a structural consultant who would stamp their imprimatur on drilling *even one new penetration* to install a mercury monitor alone. As it stands (for now, at least), one of those stacks is riddled with monitoring penetrations that comprise 33% of the stack circumference.

Clearly, drilling three new penetrations would carry the risk of weakening chimney structure at EGUs across the nation. This poses not only a worker and community safety ramification, but also impacts grid reliability, considering the year or more required to erect a replacement stack and return the unit to operation. In consideration of these factors, APPA strongly suggests that units employing PM CEMS should be exempted from Federal and state opacity monitoring requirements. As recognized by recent New Source Performance Standard (NSPS_ revisions, APPA believes that there is no need for a particulate monitor *in addition to* a surrogate particulate monitor. Since the vast majority of opacity monitors employ both a transmitter and a retroflector to double the monitoring pathlength, retirement would result in two opposing holes in which to deploy the new equipment envisioned by this rule.

Bottom line, APPA supports UARG objections to PM CEMS as untested and inappropriate technology, and UARGs assertion that if a unit chooses PM CEMS, they should not have to also monitor opacity. At a 0.01 PM limit, opacity is meaningless.

U.S. EPA's Proposed Compliance Demonstration, Recordkeeping, and Reporting Provisions Require Clarification and Revision

Although U. S. EPA provides a number of compliance options, each option presents a number of issues. Moreover, the applicability of many requirements to those options is not clear. The numerous inconsistent provisions and the absence of articulated rationale deprive APPA and its members of a reasonable opportunity to comment.

APPA agrees with UARG's comments that U. S. EPA must specify that the operating limits (including the operating load limit) apply only to EGUs using stack tests to comply or explain why those requirements are necessary for other units. APPA agrees with UARG's assumptions that the purpose of the operating limits is to demonstrate compliance between performance tests at EGUs that are not otherwise monitoring compliance with the relevant standard continuously (e.g., at EGUs not using CEMS or sorbent trap monitoring system).

Proposed § 63.10011(b) states that "if you demonstrate compliance through performance testing," you must "establish each site-specific operating limit in Table 4 . . . that applies to

[83] New monitors are specified for mercury, particulate matter, and hydrogen chloride gas. Existing monitors include opacity, flow, and SO_2/NOx/diluent, which may or may not be combined in one probe. Some stacks also monitor moisture.

you" according to the requirements in § 63.10007, Table 7 to this subpart, and paragraph (c)(6) of this section, as applicable.

Table 4 includes operating limits for various control devices. It also requires EGUs that "demonstrate compliance using . . . performance testing" to maintain their operating load such that it does not exceed "110 percent of the average operating load recorded during the most recent performance test." Proposed Table 4 (7), § 63.10007(c).

However, since all EGUs are required to demonstrate initial compliance with each emission limit "through performance testing," and the proposed rule defines "performance testing" to include the first 30 operating days of CEMS data, the proposal appears to require that EGUs meet operating limits for all relevant control devices and load regardless of the "performance testing" option they choose. See, e.g., proposed § 63.10005(a) and Table 5 (including stack tests, CEMS, and LEES in the list of "performance testing" options).

The other provisions cited in § 63.10011(b) provide little clarification. Proposed § 63.10007 does not discuss applicability. With the exception of the filterable PM limit applicable to units using PM CEMS, Table 7 does not distinguish between compliance options. Instead, Table 7 refers to various parameters depending on which control device "your operating limits are based on." Section 63.10011(c)(6) addresses fuel sampling, not operating limits. Section 63.10011(b)(6), the provision U. S. EPA likely meant to cite, refers only to control devices and not compliance options.

U. S. EPA's preamble discussion contains numerous inconsistent statements and no rationale by which one could determine U. S. EPA's intent with respect to these operating limits for units using CEMS and sorbent trap monitoring systems.

APPA agrees with UARG that there is no known rationale for requiring sources that establish compliance with the non-Hg metal limit (using PM as a surrogate and PM CEMS, with the HCl limit using HCl CEMS or an SO_2 CEMS, or with the Hg limit using Hg CEMS or a sorbent trap system) to also comply with an operating load limit, or with control device parameter operating limits for PM, HCl, or Hg controls.

U. S. EPA Has No Basis To Require HAP Stack Testing for EGUs Using Surrogates Or To Require Surrogate Testing For EGUs Not Relying on Surrogates

Where a surrogate is used to demonstrate compliance (e.g., PM for non-Hg HAP metals, or SO_2 for acid gases), U. S. EPA proposes to require rate testing for the applicable HAP "during the same compliance test period and under the same process (e.g., fuel) and control device operating conditions of the pollutant and surrogate." Proposed § 63.10005(a). For example, sources using PM as a surrogate for non-Hg HAP metals must perform metals testing in addition to stack testing for total PM and establishing a filterable PM limit and demonstrating compliance with PM CEMS. Similarly, sources using SO_2 as a surrogate for HCl must test for HCl in addition to the SO_2 CEMS performance test. The testing must be repeated every 5 years. Proposed § 63.10006(a), (b); Preamble, 76 Fed. Reg. at 25,029.

For EGUs that do not choose to use a surrogate, U. S. EPA proposes to require testing for surrogates anyway. For example, proposed § 63.10006(d) requires EGUs without PM CEMS, but with a PM control device, to perform annual tests for both PM and non-Hg HAP metals. Similarly, proposed § 63.10006(h) requires EGUs without SO_2 CEMS to conduct "all applicable performance tests" for SO_2 and HCl annually and, for units with SO_2 controls, to

conduct SO_2 emissions testing "at least every other month." See also Preamble, 76 Fed. Reg. at 25,051.

These requirements are duplicative and must be removed. Where U. S. EPA has demonstrated the appropriateness of use of a surrogate, and selected an emission limit for that surrogate that is consistent with what the best sources achieve, there is no basis for also requiring the source to test for the applicable HAP. Preamble, 76 Fed. Reg. at 25,021. Where a source chooses to comply with the HAP limit, testing for surrogates is unnecessary and unreasonable. Both requirements also are inconsistent with Tables 1 and 2, which clearly establish surrogate emission limits as "alternatives" to HAP emission limits and vice versa. Although U. S. EPA describes these duplicative testing requirements in the preamble, U. S. EPA again provides no rationale to support them. They must be removed.

A. Summary of Compliance Options and Issues

1. For coal-fired units and solid oil-derived EGUs.

a. Options for Non-Hg HAP metals

i. PM CEMS:

(1) U. S. EPA's proposed operating limit is not clear

(2) EGUs are unlikely to pass PS 11 performance criteria at the levels expected

(3) U. S. EPA should not require use of PM CEMS data to show compliance during startup and shutdown

(4) U. S. EPA must take measurement error into account when establishing a PM CEMS limit

(5) In light of the multiple measurement issues, EGUs should use PM CEMS data as indicator monitoring only

(6) U. S. EPA should provide alternative emission limits for PM, SO2, HCl and Hg during periods of PS 11 correlation testing

ii. Performance Stack Testing:

(1) U. S. EPA must remove the requirement for annual PM testing

The requirement for annual PM testing at EGUs that choose to comply with the non-Hg metals limit is not reasonable. U. S. EPA provides no justification for this requirement. Proposed Tables 1 and 2 clearly provide sources the option of meeting a PM or non-Hg metals limit. Testing for PM if no limit applies is nonsensical. Moreover, if non-Hg metals testing with Method 29 includes analysis of the impinger, any condensable metal will be measured by that test. U. S. EPA must remove references to PM testing under § 63.1006(d).

(2) U. S. EPA should re-evaluate the proposed operating parameter requirements

(3) U. S. EPA should specify minimum detection limits for laboratory analysis and provide procedures for calculating combined concentrations of single metals and total non-Hg metals

b. Options for Acid Gases

iii. HCl CEMS

(1) Performance Specifications (PS) 15 and 6 are not applicable to HCl CEMs

U. S. EPA proposes to require certification of HCl CEMS according to PS 15 or PS 6. As U. S. EPA acknowledges in the preamble, PS 15 applies only to FTIR CEMS. PS 6 applies to continuous emission rate monitoring systems (CERM), which measure mass emissions rate per unit of time. In order to provide an HCl CEMS option, U. S. EPA says, "we expect to publish [a performance specification] prior to the compliance date of this proposed rule and to make it available to source owners and operators." 76. Fed. Reg. at 25,031.

FTIR CEMS is not a viable option and sources need a well-documented HCl performance specification well in advance of the compliance date in order to evaluate and procure appropriate instrumentation. APPA supports U. S. EPA's decision to convene a workgroup of interested stakeholders to aid in development of an appropriate performance specification. However, in the absence of an existing specification, U. S. EPA should recognize in the rule that PS 15 does not apply to HCl CEMS and allow EGUs to petition U. S. EPA for use of an alternative specification if none has been promulgated by the time EGUs need to make decisions about their compliance options.

(2) U. S. EPA must clarify the subsequent performance testing requirements for units "without SO_2 CEM"

Proposed § 63.10006(h) requires EGUs "without SO_2 CEMS but with installed systems that use wet or dry flue gas desulfurization technology" to conduct "all applicable performance tests for SO_2 and HCl emissions" at least every year and to "conduct SO_2 emissions testing" at least every month. Proposed § 63.10006(i) requires EGUs "without SO_2 CEMS and without installed systems that use wet or dry flue gas desulfurization technology" to conduct "all applicable performance tests for SO_2 and HCl emissions" at least every year and to "conduct HCl emissions testing" at least every month.

U. S. EPA must make clear that these provisions do not apply to EGUs with HCl CEMS. As discussed above, there is no basis for testing of the surrogate SO_2 at a unit that is complying with the HCl standard or for HCl emissions testing at a unit with HCl CEMS. The proposed rule does not provide any procedure for SO_2 performance testing or an SO_2 emissions standard other than those applicable to units with SO_2 CEMS. Obviously, U. S. EPA did not intend and would have no basis to require EGUs to use both an HCl CEMS and an SO_2 CEMS.

(3) The proposed HCl Limit is at or near the detection limit for current HCl CEMS

Although APPA supports the option for use of HCl CEMS and urges U. S. EPA to complete work on a reasonable performance specification, APPA is concerned about the ability of HCl CEMS to accurately measure compliance with the proposed standard because the limit is at or near the detection limit for current HCl CEMS technology.

c. STACK TESTING:

(1) U.S. EPA must remove the requirement for SO2 performance testing

Proposed § 63.10006(h) and (i) include testing provisions for SO_2 for units without SO_2 CEMS. U. S. EPA must make clear that these provisions do not apply to EGUs complying through HCl stack performance testing. As discussed above, there is no basis for testing of the surrogate SO_2 at a unit that is complying with the HCl standard. In addition, the proposed rule does not provide any procedure for SO_2 performance testing or an SO_2 emissions standard other than those applicable to units with SO_2 CEMS. Obviously, U. S. EPA has no basis to require EGUs that choose to comply through stack testing to also install an SO_2 CEMS.

(2) U. S. EPA should re-evaluate the proposed operating parameter requirements

As described below, the operating parameters specified for HCl are not sufficiently connected to HCl removal or sufficiently flexible to be used as enforceable limits. U. S. EPA also must allow for adjustment of load-dependent operating parameters to account for load changes, and should use the operating parameters as indicators, not enforceable limits.

iv. SO_2 CEMS

(1) U. S. EPA should clarify the requirement for use of SO_2 controls

To qualify for this option, wet or dry flue gas desulfurization technology must be operated "at all times." Proposed § 63.9991(a)(1)(iii). U. S. EPA should make clear that this requirement is intended to disqualify EGUs that operate SO_2 controls intermittently, and not to disqualify EGUs that experience SO_2 control device malfunctions or that must turn off controls to perform maintenance. The higher SO_2 recorded by the CEMS during such periods will reflect the potential for higher HCl as well. U. S. EPA should also make clear that the existence of a bypass stack does not disqualify an EGU from complying with the SO_2 standard.

(2) U. S. EPA should allow all part 75 exceptions

Proposed 63.10010(e) allows use of an SO_2 meeting Part 75, but disallows the linearity and 7-day calibration error test exceptions and requires a calibration gas at a level equivalent to the emission limit (even if it is a fourth level). Proposed § 63.10010(e).

(3) U. S. EPA must clarify the subsequent performance testing requirements for units "without HCl CEM"

Proposed § 63.10006(j) requires EGUs "without HCl CEMS but with HCl emissions controls" to test for HCl at least every month. Proposed § 63.10006(k) requires EGUs "without HCl CEMS and without HCl emissions controls to test for HCl at least every other month." U.S. EPA must make clear that these provisions do not apply to EGUs with SO_2 CEMS. As discussed above, there is no basis for testing of HCl at a unit that is complying with the surrogate SO_2 limit.

(4) U. S. EPA should add reference to use of part 75 in the continuous compliance provisions

Proposed § 63.10021(a)(13) sets out the ongoing requirement for SO_2 CEMS. The proposed requirements are similar to proposed § 63.10010(e), except this provision does not reference the Part 75 option. U. S. EPA should reference the Part 75 alternative in this provision as well or consolidate the two provisions.

v. Options for Mercury (Hg)

If the EGU does not qualify as a low emitting EGU (LEE), initial and continuous compliance must be demonstrated using either (1) an Hg CEMS, or (2) a sorbent trap monitoring system. Proposed § 63.1000(c)(1).

a. Hg CEMS

(5) U. S. EPA should remove the reference to Procedure 5

U. S. EPA proposes ongoing quality assurance (QA) requirements for Hg CEMS in Appendix A. However, U. S. EPA also proposes in § 63.10021(1)(14) to require compliance with quarterly accuracy determinations and calibration drift tests in accordance with Part 60, Appendix F, Procedure 5. The quarterly and daily requirements in Procedure 5 are duplicative of and conflict with some of the proposed requirements in Appendix A. Use of Procedure 5 also is inconsistent with U. S. EPA's preamble statement that it considered and rejected using Procedure 5. Preamble 75 Fed. Reg. at 25,032. U. S. EPA should remove the reference to Procedure 5. If U. S. EPA intends to require use of Procedure 5, U. S. EPA must issue a new proposal and make that clear.

(6) The accuracy of Hg CEMS at or near the proposed Hg limit for existing sources is questionable

APPA supports the option for use of Hg CEMS. However, the accuracy of Hg CEMS at or near the concentration of the proposed existing source limit is questionable. Hg CEMS will not be a viable option at the proposed level of the new source limit.

vi. Sorbent Trap Monitoring System

Low Emission EGU (LEE)

As discussed above, it is not clear whether U. S. EPA intended that the proposed fuel input limit on Hg, and additional operating limits on Hg controls and load apply. Proposed § 63.10011(b), Tables 4 - 8. U. S. EPA should make clear that the fuel input, control device operating limits and load limit do not apply.

If LEE status is lost, conduct periodic emissions testing within 6 months for all HAPs or surrogates except Hg. For Hg, install a CEMS or sorbent trap system within one year. Proposed § 63.100006(c).

(1) U. S. EPA should expand the LEE option to new units

As proposed, the option to qualify a unit as a LEE applies only to existing units. New units also should be eligible.

(2) U. S. EPA should remove or explain the references to operating parameter limits for LEEs

Proposed § 63.10005(k)(3) and § 63.10006(c) refer to establishment and maintenance of operating parameter limits. However, the provision cited for establishing such limits does not exist and no other provision addresses parameters for LEE. Proposed § 63.10021(a)(17) states that for LEEs, results of emissions tests and fuel analysis demonstrate continuous compliance. The provision does not mention operating limits. Moreover, U. S. EPA's descriptions of the requirements for both LEEs suggest they are not required to establish or comply with operating parameter limits.

(3) U. S. EPA should clarify the required testing period

Proposed § 63.10005(k) refers to a 28-30 operating day performance test. Proposed Table 5 requires 30 days.

(4) U. S. EPA should explain the 10-day limit on use of trap

Under proposed Table 2, LEE testing is limited to 10 days per run. The purpose of this limit is not explained. U. S. EPA's Appendix A allows up to 14 days.

U. S. EPA's Proposed Operating Parameters Are Not Sufficiently Connected to Emission Limits to Be Enforceable Limits

APPA agrees with UARGs objections to U. S. EPA's proposal to set enforceable operating limits based on control device parameters measured during performance testing. Establishment of such limits reduces operational flexibility, deprives sources of the use of any control device margin, and allows enforcement for events beyond the owner/operator's control.

U. S. EPA's current proposal is based on the faulty assumptions that the values of the parameters identified by U.S. EPA have a direct relationship to the level of emissions, and that exceeding those limits therefore indicates an exceedance of the emission limit as well. To the extent possible, source owners and operators will contract for control equipment that is designed to provide a "margin of compliance" with the applicable emission limitation. In addition to reducing the possibility of an exceedance of the limit, this margin is intended to provide flexibility for the source to account for an inevitable control equipment or operational problem. Any source that is able to normally operate with a margin of compliance will lose part of that margin of compliance if they conduct performance testing under normal operations, because they will establish operating limits that would require them to continue to over-control forever. The only way such sources could avoid surrendering whatever margin of compliance they have would be to deliberately reduce performance of their controls to attempt to generate the least stringent operating limits consistent with achievement of the applicable emission standard. U. S. EPA's proposal thus has the perverse result of encouraging sources to focus their attention on learning how to manipulate their operations to allow testing as close as possible to their emission limit by reducing the performance of their controls.

Unfortunately, even the "detuning" of a control device during performance testing will not ensure that the operating limits established during the test are reasonable or necessary for achievement of the applicable emission limit. As U. S. EPA has previously recognized in the context of the NSPS and the CAM rule "many sources operate well within permitted limits over a range of process and pollution control device operating parameters," and requiring sources to continuously maintain parameters that "happened to exist" during the most recent performance test may not be "possible or wise." 62 Fed. Reg. 54,900, 54,907, 54,926-27.

That is because control device parameters, such as those identified by U. S. EPA for scrubbers and ESPs, do not necessarily have a direct relationship to emissions, but instead are interrelated with the design of the control device and the interaction of various parameters. As a result, a single parameter may vary widely with little effect on emissions.[84] For example, ESP power may be completely unrelated to ESP performance for a multi-sectional ESP. Id. at 2 and Appendix 1. This power approach for ESPs simply does not work and that fact is easily demonstrated in the cited material. Similarly, because scrubber pressure drop and liquid flow rate are usually a function of boiler load, levels of those parameters above or below those recorded during a performance test are not necessarily indicative of emissions levels at a different load. Id at 2. Many industrial boilers operate at variable load levels because they follow process demand. As the load drops, the scrubber pressure drop also moves down. This change does not necessarily indicate a drop in scrubber performance. In fact, the scrubber performance is likely to improve at reduced load.

Although U. S. EPA's provision of a 10% difference from the average tested value recognizes some of the normal operational variability of control devices, it may not be sufficient in some circumstances. Without a clear correlation between such operating parameters and the applicable emission limit, imposition of those values as enforceable limits would unreasonably restrict source and control device operation and subject sources to potential enforcement without any evidence that an emission limits has been violated.

Issues With Use of ESP Power

Under U. S. EPA's proposal, units that use an ESP in combination with a wet scrubber must comply with operating limits on secondary power input to the ESP collection plates. Proposed § 63.10011(b)(6)(iii). U. S. EPA's proposal is flawed. ESP power input simply is not directly related to PM removal performance, particularly for the modern multi-section ESPs that are likely to be installed to comply with a proposed MACT. See UARG Comments on Proposed Reconsideration and Revision of New Source Performance Standards, U. S. EPA-HQ-OAR-2005-0031-0246 (Mar. 27, 2007) at 21-22, and Attachment 2 (incorporated by reference); UARG Comments U.S . EPA-HQ-OAR-2002-0058-0413, Attachment C, Appendix 1. Moreover, none of the ESP parameters are likely to have any relationship to PM at units that also have a wet scrubber, since those systems also are highly effective in controlling high levels of PM coming out of an ESP that is not performing at its intended control efficiency. See U. S. EPA-HQ-OAR-2005-0031-0246 at 15-16.

Issues with Use of pH, Pressure Drop, Liquid Flow-Rate, and Sorbent Injection Rate for Scrubbers

Under U. S. EPA's proposal, units that use a wet scrubber must comply with operating limits for pH, pressure drop and liquid flow-rate; and units that use a dry scrubber must comply with an operating limit on sorbent injection rate. Proposed § 63.20011b)(6)(i), (ii), and (iv). U. S. EPA's proposal to use these parameters is subject to the same flaws as U. S. EPA's other proposed operating limits -- namely the lack of a sufficient relationship between the parameters measured during performance testing and actual emissions. For example, as described above, because scrubber pressure drop, liquid flow rate, and sorbent injection rate vary with boiler load, establishment of a limit based on conditions during performance testing may tell U. S. EPA little about actual emissions under other load conditions. Moreover, when U. S. EPA in 2008 considered the relationship between liquid flow rate and PM in the context

[84] See UARG Comments on Proposed National Emission Standards (Mar. 14, 2003), U. S. EPA-HQ-OAR-2002-0058-0413, Attachment C (incorporated by reference).

of the NSPS for electric steam generating units at 40 C.F.R. Subpart Da, U. S. EPA concluded that, at the level of the NSPS (i.e., 0.015 lb/mmBtu), PM emissions controlled by an ESP were not particularly sensitive to the actual liquid flow rate. U. S. EPA "Response to Public Comments on Rule Amendments Proposed June 12, 2008 (73 FR 33642)" (Nov. 2008), U.S. EPA-HQ-OAR-2005-0031-0284, at § 2.5.3.

U. S. EPA Has No Basis To Expect That Operating Parameter Limits Established During Performance Tests Will Be Achievable During Startup, Shutdown, and Malfunction

APPA is very concerned about the potential for enforcement of operating parameter and opacity limits during periods of startup, shutdown, and in the event of equipment malfunction. U. S. EPA's current proposal would allow enforcement of deviations from operating parameters during periods of startup and shutdown, when controls would not be expected to be operating at the same levels as during performance tests. In the preamble, U. S. EPA discusses its approach to these events. 76 Fed. Reg. at 25,028. Regarding startup and shutdown, U. S. EPA asserts that it has taken these periods into account by proposing use of 30-boiler-operating-day rolling averages and by the fact that EGUs often use cleaner fuel during startup. Id.

U. S. EPA's preamble assertions regarding startup and shutdown are inapplicable to control device operating parameter limits, which are based on 12-hour averages (30-day rolling averages) established during performance tests (not based on CEMS data that include startup and shutdown). In short, **U. S. EPA has made absolutely no allowance in its operating limits for periods of startup and shutdown. To the contrary, U. S. EPA has proposed to require sources to establish control device operating parameter levels that are dependent upon load during periods of "maximum normal operating load," or other frequently used loads, and then maintain those levels during other periods, including startup and shutdown.** U. S. EPA's proposal is patently unreasonable. U. S. EPA must address these periods in some other manner, for example by establishing simple work practice standards in lieu of operating parameters.

The use of 30-day rolling averages with SSM could result in exceedances of the 30-day standards. The following comments provide a mathematical example of the error in U. S. EPA's inclusion of SSM instances in the rolling averages. This is tantamount to gaming the system to tighten standards by using circumstances outside of an entities control. The following example uses particulate matter (PM), but the same would apply to other pollutants:

Given:

A = average PM emission rate during SSM, lb/MMbtu
B = average PM emission rate during normal operation, lb/MMbtu
X = time fraction spent during SSM at "A" lb/MMbtu
(1 – X) = time fraction spent during "normal" operation at "B" lb/MMbtu
0.03 = 30 day rolling average PM standard under MACT

Then you can say:

$A*X + (1 – X) *B = 0.03$

Solving for "X" :

X = (0.03 – B)/(A – B)

Multiplying "X" by 720 hrs gives you the number of SSM hours out of the 30-day rolling average that will result in exceedance of the standard ("hours-to-exceed").

If a PM emission rate during startup without an ESP, was 0.45 lb/MMbtu ("A"). The annual average PM during normal operation ("B") is 0.02 lb/MMbtu.

This gives an "X" of 0.023 or 16.7 hours. Thus theoretically, it is possible that several short back-to-back outages could exceed the 30-day standard.

Additionally, if a scrubber is in operation it has the potential to increase PM emissions. If we assume a "normal" PM emission rate of 0.28 lb/MMbtu ("B") with the scrubber in service combined with an SSM emission rate of 0.45 ("B"), then the hours-to-exceed becomes only 3.4 hours. **In this case, one forced outage might then cause an exceedance. A forced outage is out of the utility's control and should not ever be able to cause an exceedance of emissions limits. By excluding SSM, EPA has mandated a more stringent standard than 0.03 lb/MMbtu, in some cases this standard is MUCH more stringent depending on the SSM operating emission rate.** A graph of the hours of operation it would take to exceed the U. S. EPA's 30-day standard as a function of "Normal" emission rate for various SSM PM emission rates in lb/MMbtu can be found below in Figure 6.

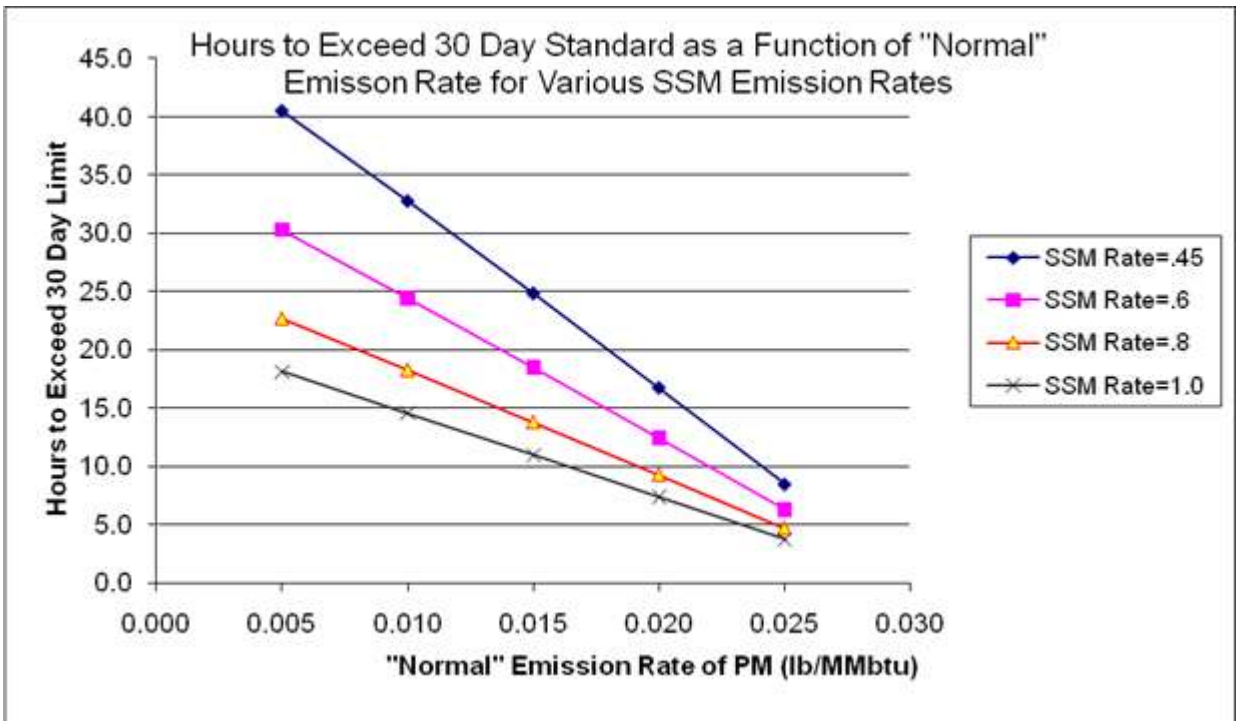

Figure 6: Graph of hours of operation it would take to Exceed EPA's 30 Day Standard as a function of "Normal" emission Rate for Various SSM PM Emission Rates in lb/MMbtu.

APPA Agrees with UARG's Assertion that U. S. EPA Should Require Sources To Establish Source-Specific Control Device Parameter Ranges And Enforceable Response Requirements, Not Enforceable Operating Limits

Rather than establish enforceable operating limits, U. S. EPA should use the approach taken in the CAM rule and require sources to establish site-specific operating parameter ranges to define conditions under which compliance with the applicable limit can be reasonably assured. This approach already has been upheld as sufficient *to satisfy the CAA's* requirements for demonstrating continuous compliance. See NRDC v. U.S. EPA, 194 F.3d 130, 135-37 (D.C. Cir. 1999) (rejecting NRDC's argument that the CAM rule's "reasonable assurance of compliance" is not sufficient to assure continuous compliance as required by the CAA). Source owners and operators would then be required to monitor those parameters and respond to changes that indicate problems with the controls that could jeopardize compliance.

Whether using a single control device or combination of devices, sources are in the best position to determine what parameters and levels are consistent with compliance. In many cases, multiple parameter relationships or supplemental operational data will provide a higher level of compliance assurance than the level that happens to be measured during a discrete performance test. This is particularly true for sources with a significant margin of compliance. U. S. EPA-HQ-OAR-2002-0058-0413, Attachment C at 4. In addition, units with significant margins of compliance should be allowed to establish operating levels by extrapolating parameter data beyond that obtained during a performance test, based on other information. Allowing such extrapolations is essential for some sources to provide needed operational flexibility. Attempting to establish "worst case" test conditions on a scrubber or multi-section ESP, where the possible combinations of parameters are numerous, would at the least be difficult and could be impossible without a major research effort. Id. Allowing extrapolation of results avoids the necessity of repeated testing.

Once sources have established appropriate operating parameter ranges based on data collected during performance tests, as well as other operating data and engineering principles, those parameters would be monitored and any deviation from them would trigger a requirement for investigation and corrective action to return the parameter to the appropriate range. Although this range may in some cases be similar to the minimum values that would be established under U.S. EPA's proposed rule, allowing sources to respond with corrective action (rather than simply record exceedances and report deviations) achieves U. S. EPA's intended result without subjecting sources to potential unreasonable enforcement.

Bag Leak Detection Systems

Under U. S. EPA's proposal, units that use a fabric filter (whether or not using a wet scrubber) and that "choose to demonstrate continuous compliance using a BLDS" must install, operate, calibrate and maintain a BLDS in accordance with U. S. EPA's "Fabric Filter Bag Leak Detection Guidance," U. S. EPA-454/R-98-015 (Sept. 1997). Proposed §§ 63.10010(h)(2)(v). The BLDS must be certified by the manufacturer to be capable of detecting PM at a concentration of 10 milligrams per actual cubic meter or less. Id. The BLDS must be operated such that the sum of the duration of alarms does not exceed 5% of the operating time during any 6-month period. Proposed §§ 63.10011(b)(6)(v); 63.1021(a)(9). Records must be kept of each alarm period. If inspection of the bag demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, the alarm time is counted as the actual time taken to initiate corrective action with a minimum of one hour counted for each alarm. Proposed § 63.1021(a)(9).

Applicability of the requirements for fabric filters is unclear. Although several provisions suggests that BLDS are required only if an EGU "chooses" to demonstrate compliance using a BLDS, other provisions appear to require any EGU with a fabric filter to employ a BLDS along with any other applicable operating limits. Proposed Tables 4-8. U. S. EPA should issue a proposal that makes clear when a BLDS would be required and to justify that requirement.

In addition, U. S. EPA's guidance has no place as a regulatory requirement. U. S. EPA's guidance addresses only one type of BLDS (the "triboelectric") and is based on information provided by a single manufacturer. The definition of BLDS clearly allows use of a variety of technologies, including electrodynamic, light scattering, and light transmittance. Proposed § 63.10042. The guidance explains that the alarm setting procedure is dependent on the type and configuration of the fabric filter and filter cleaning cycle. But it addresses only one baghouse configuration. The document excludes all other technologies (e.g., light scattering, light transmission, optical scintillation, and electro-dynamic devices). In short, the existing Guidance Document is out of date and is technically flawed.

D. Reporting

1. Reporting Using ERT

(a) U. S. EPA Cannot Require Sources to Report Using ERT

XV. Oil-fired units in Alaska, Puerto Rico, American Samoa, and Guam require special considerations: APPA supports waiver for oil-fired units in Guam, Puerto Rico Hawaii and Alaska Oil Units

APPA has member utilities in locations that are uniquely isolated including islands, or areas of the country that are not connected to the national utility or industrial infrastructure. These locations have special needs for delivery of pollution control devices, installation, working around seasonal loads, scheduled outages and extreme economic impacts due to extended outages for installation.

APPA supports the petitions presented by Guam, Puerto Rico, Hawaii, and Alaska to exempt their oil-fired power plants from the new nickel limits. APPA defers to that petition as to the specific treatment. APPA notes that because of the relationship between investor, electric co-op and public power (municipal or state owned utilities), we believe the language offered by the petitioners should cover all utilities on those "islands" (including Alaska, which functions as an island due to its isolation). Appendix O shows the Guam Oil-Fired capacity units and date of installation.[85]

XVII. Relationship between EGU MACT and Coal Ash/Coal Combustion Residuals Rulemaking

APPA believes that the U. S. EPA has proposed a rule that would make many coal-fired power plants seek to use DSI as a control technology in order to maintain some fuel diversity in their utility portfolio. As a result of using DSI as a control technology, many existing power plants using coal may learn that their coal ash may not be tradable or commercially viable for sale to a cement company due to the sodium content. The cement industry has ASTM (formally known as American Society for Testing and Materials)[86] standards on sodium content. The DSI control technology will have an unintended consequence of

[85] FY 2008 Guam Generation Resource Handbook
[86] http://www.astm.org/ABOUT/overview.html

increasing the sodium content making it unsuitable to the commercial users of coal ash.

For municipal electric utilities, simply making the ash undesirable to the cement industry (due to sodium content from DSI technology) would often mean a dramatic increase in the cost of disposal. In fact, it would be akin to designating the coal ash as a hazardous substance since the public power utilities would not have the ability to sell or trade the ash to a local cement industry. Ash disposal costs to a community owned utility can be enormously expensive. These coal ash disposal costs can range between 5% and 24% of a municipal government's revenues (when considering larger public power utilities that exceed the SBREFA threshold). The typical cost range is between 2% and 14%, depending upon proximity to a hazardous waste landfill (Source: APPA's comments to the U. S. EPA on coal ash, Nov. 2010).

Table 3 - Examples of Additional Costs to Some Smaller Municipal Utilities for CCR Disposal as Hazardous Waste

Utility	Total Ultimate Customers	Residential Customers	Amount of CCR (tons)	Disposal Cost at $100/ton	Revenues	Percent of Revenues for Disposal as Hazardous Waste
Muscatine, IA	11,797	9,663	44,196	$4,419,600	$68,200,000	6.5%
Orrville, OH	6,933	6,076	20,000	$2,000,000	$22,336,000	9.0%
Holland, MI	30,136	25,375	23,086	$2,308,600	$78,195,000[1]	3.0%
Manitowoc, WI	17,828	15,621	79,774	$7,977,400	$54,290,000	14.7%
Painesville, OH	12,056	10,167	5,396	$539,600	$22,150,000	2.4%
Michigan South Central Power Agency	20,606	17,170	28,596	$2,859,600	$47,987,421	6.0%
Marquette, MI	15,675	13,845	23,926	$2,392,600	$23,934,000	10.0%
Hamilton, OH[2]	29,480	26,481	32,782	$3,278,200	$59,567,000	5.5%

Source: APPA's comments to EPA on proposed RCRA regulation, November, 2010.

Disposal of CCRs as hazardous waste (estimated at the very conservative figure of $100/ton) could reach 21% of the revenues for some governmental or municipal utilities. From the cost estimates offered by municipal utilities during the EPA coal ash or CCR comment period, it is clear that the EPA's estimated $100/ton disposal cost was too low. Many utilities offered disposal costs that could exceed **$200/ton,** depending on the details of EPA's final coal ash or CCR rule. Much of the cost increases are increased disposal costs and transportation costs. Ohio, for example, has only one hazardous waste landfill which is across the state from Orrville (a public power or community owned electric utility); Orrville estimated their disposal costs to be $100/ton.

Another key flaw in the proposal is the RIA's failure to consider the adverse impacts that certain of the control technologies upon which the emission controls are predicated – including in particular sodium-based dry sorbent injection and activated carbon injection (ACI) – will have on the marketability and beneficial use of fly ash in important industry segments. The loss of these important beneficial uses – which comprise a material percentage of the total amount of coal combustion residuals beneficially used on an annual basis – will cause these CCRs to have to be disposed of, as opposed to being beneficially used, causing significant and new economic and operational burdens on power generation facilities and resulting in the forfeiture of significant greenhouse gas (GHG) emission reductions achieved through these beneficial uses. These economic burdens and associated

loss of carbon reductions must be evaluated by EPA as part of this rulemaking.

The Recycling of Fly Ash Will Be Undermined Because of Emission Control Technologies Contemplated in the Proposal

Currently, approximately 134 million tons of CCRs are generated annually, of which approximately 56 million tons, or approximately 41%, are recycled in a variety of applications. *See* 2009 Coal Combustion Product (CCP) Product and Use Survey, American Coal Ash Association ("ACAA Survey"). Of critical importance to this rulemaking, almost a quarter of these beneficial use applications involves the use of fly ash as replacement for cement in the production of concrete (in the ready mix concrete industry) and as a raw feed material in the manufacture of cement (a combined total of approximately 12 million tons per year). *See* ACAA Survey. The employment of sodium-based dry sorbent injection and ACI technologies by power generation facilities, however, will render the vast majority of this approximately 12 million tons of CCRs generated annually unfit for these beneficial use applications, causing this significant volume of CCRs to have be disposed of instead of entering the beneficial use market.

The problem arises because, for fly ash to be used in certain applications, the fly ash must meet product specifications. For example, the American Association of State Highway and Transportation Officials ("AASHTO") has set a maximum allowed "alkali" content for the use of fly ash in concrete at a maximum of 1.5%. AASHTO M295. AASHTO M 295 (along with ASTM C 618) are used within the industry to provide a guide to assure that fly ash when used as a concrete admixture conforms to a specified range of physical and chemical properties. Conformity assures that a consistent, high quality product is produced. Alkali silica reaction (ASR) is the reaction between the alkali hydroxide in Portland cement and certain siliceous rocks and minerals present in the aggregates. The products of this reaction often result in significant concrete expansion and cracking, and ultimately failure of the concrete structure. Therefore, an alkali limit was established for mineral admixtures such as fly ash that are used in concrete containing reactive aggregate and cement.

Preliminary testing, however, shows that sodium-based sorbent injection technologies will cause fly ash to exceed the 1.5% available alkali criteria. Sodium-based dry sorbents are soluble and therefore contribute greatly to the available alkali content. As a result, fly ash produced with emission controls systems employing sodium-based dry sorbent injection technologies – upon which EPA based certain key emission and cost assumptions in the proposal – will no longer be suitable for use in the ready-mix concrete industry.

Compounding this problem is that the use of sodium-based dry sorbent injection technologies also increases the solubility of certain other constituents in the fly ash, which would potentially make it unsuitable for other established and environmentally beneficial uses, including for mine reclamation. In 2009, approximately two million tons of fly ash were beneficially used in mine reclamation projects (ACAA Survey). These fly ash beneficial use applications would also be at risk if sodium-based dry sorbent injection technologies serve as the basis for key emission control strategies in the final rule.

In addition to sodium-based dry sorbent injection, the use of ACI technologies will cause some fly ash to be unsuitable for use as a cement replacement in ready mix concrete due to increased carbon content. The increased carbon content attributable to ACI renders the fly ash unsuitable for use in ready mix concrete because the highly reactive carbon adsorbs air entraining agents.

The RIA Must Account for Lost Emission Reductions and Increased CCR Management Costs Due to the Emission Control Technologies Contemplated in the Proposal
EPA has consistently extolled the environmental benefits of the beneficial use of CCRs. In Congressional testimony, EPA testified that the "beneficial use of CCR saves virgin resources, reduces energy consumption, reduces GHG emissions, and reduces the need for land disposal." *See* EPA Written Testimony before the Senate Committee on Environment and Public Works (Jan. 8, 2009) ("EPA Testimony"). Of particular relevance to this proposal, EPA emphasized that "coal ash can typically replace between 15% and 30% of the Portland cement used in concrete." The GHG savings from these beneficial use practices are dramatic – in 2007 alone, EPA reported that "by recycling 13.7 million tons of fly ash and using it in place of Portland cement, the United States saved nearly 73 trillion BTUs of energy, equivalent to the annual energy consumption of more than 676,000 households." *Id.* at 8. These beneficial use activities also resulted in GHG emissions reductions "by 12.4 million metric tons of carbon dioxide equivalent, equivalent to the annual GHG emissions of 2.3 million cars." *Id.*[87]

Any environmental forfeiture of this magnitude caused by reliance on the sodium-based dry sorbent injection and ACI technologies contemplated in the proposal must be assessed and considered in the overall policy evaluation and RIA underlying the proposal. **EPA has not conducted this evaluation in the proposal's RIA**.

Not only will reliance on these emission control technologies result in the forfeiture of significant GHG emission reductions, they also will result in greater volumes of CCRs having to be disposed of. Specifically, establishment of emission control technologies predicated on sodium-based dry sorbent injection and ACI will likely mean that approximately 12 million tons of fly ash (if not more) will be diverted on an annual basis from its beneficial use in the cement/concrete industries to CCR disposal units. Coal-based facilities will need to accommodate these additional volumes of CCRs through expansions of existing disposal units and/or construction of new units. The design, planning, permitting and construction of this additional disposal capacity can take many years and cost millions of dollars per unit. The RIA must take into account the additional construction and disposal costs that coal-based generating units will have to incur to dispose of additional CCRs that will be diverted from the beneficial use market to the disposal market as a result of the contemplated emission control technologies underlying the proposal.

U. S. EPA has underestimated higher coal transportation costs affected by the U. S. EPA EGU MACT rulemaking: more captive rail impacts resulting from reliance upon western coal and transport of coal ash to permitted landfills.

The electric utility sector has transportation costs that are influenced by the limitations of the U. S. rail system. Captive rail customers are shippers who must rely on a single railroad to deliver their products. These customers usually move bulk commodities such as coal, grain or lumber, or certain materials that, due to size or characteristics, cannot be moved on our nation's highways.

Historically, 20-30 percent of the nation's rail movements have been "captive," with many of these movements covering rural America. According to a recent study commissioned by the

[87] S*ee also* Testimony of Barry Breen, Acting Assistant Administrator Office of Solid Waste and Emergency Response before the House Committee on Transportation and Infrastructure, Subcommittee on Water Resources and the Environment (April 30, 2009).

Surface Transportation Board, **44% of all tonnage shipped by freight rail is "captive"** (routes served by only one rail carrier line). The study, which was commissioned by the Surface Transportation Board (STB), provides evidence previously denied by the freight railroad industry that they are abusing their unique exemption from antitrust law to exert anticompetitive business practices – by charging shipping rates 500 to 700 percent above cost and refusing to provide adequate service to freight rail shippers who are captive to only one railroad. For additional information on captive rail, please see http://www.railcure.org/about/about_customer.asp.

APPA notes that there may be unintended cost consequences to eastern coal varieties because utilities using eastern coal may not be able to meet the EGU MACT/NSPS proposed rule. APPA notes that use of western coals by the remaining coal fired power plants may well cause utilities of all sizes to be more reliant upon rail transportation due to moving more western coal to more power plants. As captive customers of rail companies, power plants would pay significantly more for delivery of western coals. The displacement of the eastern coal, cost and the related transportation impacts were not considered by the U. S. EPA. The costs of transportation of coal are almost always more expensive than the cost of the coal itself. If the U. S. EPA's final EGU MACT/NSPS rulemaking causes more fuel switching from eastern to western coals, the additional transportation costs (and captive rail cost concerns) may well be another major factor not considered in the U. S. EPA Regulatory Impact Analysis (RIA). This is yet another reason why the U. S. EPA's failure to subcategorize between eastern and western coal represents a serious technical flaw which is unlikely to survive judicial challenge.

Conclusions

Essential Corrections to EGU MACT Rule:

1) U. S. EPA should re-propose the rule and the final EGU MACT should not include acid gases or PM regulatory controls.
2) Public power utilities need more time for compliance for planning, public hearings, financing, procurement and construction so the U. S. EPA and the President should grant extensions.
3) U. S. EPA should provide more flexibility including subcategories for public power, electric co-ops, IOUs and merchant power.

   These subcategories include:
   - ≤100 MW for all types of utilities
   - ≤30% capacity factor peaking units (limited use – mostly for renewables)
   - NERC Reliability Standard CIP 002-4 units
   - By fuel type
   - Those utilities with physical space constraints

- APPA believes that the U. S. EPA did not carry out its statutorily required actions and full analysis under RFA "Reg Flex" and UMRA as well as SBREFA. This poor analysis reflects both a poor analytical preparation for the rulemaking and a disregard to what the EPA was told during the U. S. EPA SBREFA SER panel meeting on December 2, 2010.

- APPA believes that the EPA did not adequately consider the disproportionately large cost of compliance faced by small communities.

- The EPA RIA failed to identify how many of the public power units will be implementing control technologies under separate Clean Air Act regulations.

- APPA believes that the U. S. EPA has grossly underestimated the number of coal-fired generation retirements at only 9.9 GW, which is only 3% of all coal-fired capacity, by the year 2015.

- Natural gas prices for consumers and utilities will almost certainly increase more than projected by U. S. EPA's RIA.

- APPA believes that three years from the date of publication of the final rule is an unrealistic timeline for compliance given the need for municipal governments to issue and conduct resource planning for fuels, issue and review requests for proposal, obtain financing or issue debt/bonds to pay for projects, and coordinate with contractors, labor unions, and crane operators, along with any permits needed for construction and transportation.

- As part of providing for the 77 months needed to complete pollution control projects APPA strongly urges the U. S. EPA to provide an industry wide extension, or one-year along with Presidential extensions, to reduce the burden on electric utilities, state permitting agencies and the consumers of electricity who will pay for the compliance costs. Further, public power utilities need a categorical extension based upon time constrained feasibility due to local ordinance duties.

- APPA believes that the U. S. EPA has made a significant error in its proposed rule on mercury under the NESHAP program by adding extraneous regulatory controls for acid gases and $PM^{2.5}$.

- APPA is a member of UARG and endorses UARG's technical comments on this proposed EGU or Mercury MACT and the proposed NSPS rulemaking pertaining to data availability, data analysis and the identification of conversion errors. APPA also endorses UARG's comments offered separately on EGU MACT monitoring.

- EPA did not adequately subcategorize to accommodate many of APPA's small and medium-sized public power utilities. In particular, EPA did not avail itself of the opportunity to use subcategories for public power electric utilities, HCl, coal rank, and for rural and isolated power plants that may not have equal options for fuel and many other fuel type subcategories.

- APPA does not believe that the U. S. EPA sufficiently considered its ability within the Clean Air Act to use Generally Available Control Technology (GACT) for smaller emitters of air toxics.

- U. S. EPA's feasibility and cost analysis did not adequately address physical space and age of plant issues when setting Best Demonstrated Technology (BDT), MACT and NSPS. In not addressing the age and space issues associated with including so many control technologies, the U. S. EPA has wrongly produced a rule that will make older plants and smaller plants unable to meet the new standards.

- The U. S. EPA should acknowledge that the price of compliance <u>increases</u> as the size of the generating unit <u>decreases</u>.

- APPA believes that the U. S. EPA's estimate of benefits and costs resulting from this proposed rule exaggerate the human health benefits dramatically because of its inclusion of $PM^{2.5}$.

- APPA believes that the proposed rule's initial new source limits were unrealistic and miscalculated based upon contractor errors (See UARG letter to U. S. EPA, dated May 6, 2011 in Appendix G).

- APPA believes the U. S. EPA should be commended for using work practices in lieu of CO limits but we do ask EPA to consider UARG's technical comments.

- The proposed NSPS for SO_2, PM, and NO_x are NOT Achievable.

- **U. S. EPA did not properly and thoroughly investigate and address the significant costs imposed on all electricity customers by this proposed rule. The U. S. EPA also should attempt to address the unproductive costs of compliance that will occur due to RTO market structures.**

- U. S. EPA's final EGU MACT (without the unnecessary acid gas or PM limit related controls) should include an administrative noncompliance procedure under the Clean Air Act's Title V permitting program. This would ensure timely reductions in mercury in the instances where electric utilities required to provide electricity under local laws ("obligation to serve") are unable to procure, finance, construct, install and calibrate the pollution control equipment by the final rule's compliance date. This procedure is allowed under the existing Clean Air Act.

- The U. S. EPA should correct the New Source Review (NSR) enforcement policy, given the significant pollution control equipment installations.

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Appendices

A. *Development of Additional Subcategory for Electric Generating Units Less Than 100 MW*
www.publicpower.org/files/appa%5Fsupport%5Ffor%5Fsmall%5Funit%5Fsubcategory%5Ffinal.pdf (Full text available on the following pages of these appendices)

B. Payments and Contributions by Public Power Distribution Systems to State and Local Governments, 2008 Data
www.publicpower.org/files/Pilot%20Report%202008.pdf

C. Small Business Administration (SBA) Letter on EGU GHG NSPS to U. S. EPA (6/13/2011)
www.publicpower.org/files/SBA%20EGU%20GHG%20NSPS%20%2D%20Response%20to%20convening%20%2D%20Public%20%2D%202011%2D06%2D13.pdf

D. Unfunded Mandates Reform Act of 1995
www.publicpower.org/files/Unfunded%20Mandates%20Act%20of%201995%2E%20%28Autosaved%29%202.doc

E. APPA's Comments to U. S. EPA and SBA regarding EGU MACT (and pointing out the benefits of using GACT to reduce regulatory costs and burdens) – December 2, 2010
http://www.publicpower.org/files/PDFs/Comments%20to%20SBA%20on%20EGU%20MACT%20rule_%2833698244%29.pdf (Full text available on the following pages of these appendices)

F. APPA's Clean Air Mercury Rule Comments www.publicpower.org/files/EPA20040629captrade.pdf

G. The Feasibility of EPA's Proposed Utility HAP Compliance Requirements
www.publicpower.org/files/Compliance%20deadline%20feasibility%2023July%5FFNL%5Ftimeline%20%282%29%20%2D%20Doug%20Carter.pdf

H. Technical Report from UARG
www.publicpower.org/files/UARG%20Comments%202010.pdf

I. UARG Request for MACT Comments Extension, May 6, 2011
www.publicpower.org/files/uarg%20request%20mact%20extension%205%2D11.pdf

J. Neophytes Guide
www.publicpower.org/files/Neophytes%20Guide.pdf

K. Why New CO_2 Regulations Could Produce Windfall Profits and Unproductive Costs for Consumers
www.publicpower.org/files/PDFs/IssueBriefWindfallProfitsandEPARegsMarch2011.pdf
(Full text available on the following pages of these appendices)

L. *Retire or Retrofit? A Look at U. S. Regional Scrubbed Coal Capacity*, SNL Energy Data Dispatch Article, Feb. 24, 2011
www.publicpower.org/files/Retire%20or%20retrofit%20%2D%20%20A%20look%20at%20US%20regional%20scrubbed%20coal%20capacity.pdf

Upcoming, Recent Coal-Fired Power Unit Retirements, SNL Energy Data Dispatch Article, Feb. 22, 2011
www.publicpower.org/files/Upcoming%2C%20recent%20coal%2Dfired%20power%20unit%20retirements.pdf

M. Implications of Greater Reliance on Natural Gas for Electricity Generation - APPA's Natural Gas Study
https://appanet.cms-plus.com/files/PDFs/ImplicationsOfGreaterRelianceOnNGforElectricityGeneration.pdf

N. Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies by Ed Cichanowicz www.publicpower.org/files/PDFs/CichanowiczCostEffectiveness.pdf

O. Guam's Oil-Fired Capacity Units & Date of Installation

Unit	Year Unit Installed	Nameplate Capacity Rating	Technology	Primary Fuel	MACT Affected
Cabras #1	1974	66.0	Steam	Residual Fuel Oil	**Yes**
Cabras #2	1975	66.0	Steam	Residual Fuel Oil	**Yes**
Cabras #3	1995	39.3	Slow Speed Diesel	Residual Fuel Oil	**Yes**
Cabras #4	1996	39.3	Slow Speed Diesel	Residual Fuel Oil	**Yes**
MEC #8	1999	44.2	Slow Speed Diesel	Residual Fuel Oil	**Yes**
MEC #9	1999	44.2	Slow Speed Diesel	Residual Fuel Oil	**Yes**
Tanguisson #1	1971	26.5	Steam	Residual Fuel Oil	**Yes**
Tanguisson #2	1973	26.5	Steam	Residual Fuel Oil	**Yes**
Dededo C.T. #1	1992	23.0	Frame 5	Ultra Low Sulfur Diesel Oil	No
Dededo C.T. #2	1994	22.0	Frame 5	Ultra Low Sulfur Diesel Oil	No
Macheche C.T.	1993	22.0	LM2500	Ultra Low Sulfur Diesel Oil	No
Marbo C.T.	1995	16.0	FIAT TG-16	Ultra Low Sulfur Diesel Oil	No
Yigo C.T.	1993	22.0	LM2500	Ultra Low Sulfur Diesel Oil	No
Tenjo #1	1993	4.4	Caterpillar Model 3616	Ultra Low Sulfur Diesel Oil	No
Tenjo #2	1993	4.4	Caterpillar Model 3616	Ultra Low Sulfur Diesel Oil	No
Tenjo #3	1993	4.4	Caterpillar Model 3616	Ultra Low Sulfur Diesel Oil	No
Tenjo #4	1993	4.4	Caterpillar Model 3616	Ultra Low Sulfur Diesel Oil	No
Tenjo #5	1993	4.4	Caterpillar Model 3616	Ultra Low Sulfur Diesel Oil	No
Tenjo #6	1993	4.4	Caterpillar Model 3616	Ultra Low Sulfur Diesel Oil	No
Dededo Ultra Low Sulfur Diesel Oil #1	1971	2.5	Diesel Unit	Ultra Low Sulfur Diesel Oil	No
Dededo Ultra Low Sulfur Diesel Oil #2	1971	2.5	Diesel Unit	Ultra Low Sulfur Diesel Oil	No
Dededo Ultra Low Sulfur Diesel Oil #3	1971	2.5	Diesel Unit	Ultra Low Sulfur Diesel Oil	No
Dededo Ultra Low Sulfur Diesel Oil #4	1971	2.5	Diesel Unit	Ultra Low Sulfur Diesel Oil	No
Manenggon #1 (MDI)	1994	5.3	Wartsila, Model 16V32	Ultra Low Sulfur Diesel Oil	No
Manenggon #2 (MDI)	1994	5.3	Wartsila, Model 16V32	Ultra Low Sulfur Diesel Oil	No
Talofofo #1	1993	4.4	Caterpillar Model 3616	Ultra Low Sulfur Diesel Oil	No
Talofofo #2	1993	4.4	Caterpillar Model 3616	Ultra Low Sulfur Diesel Oil	No
TEMES	1998	40.0	Frame 6	Ultra Low Sulfur Diesel Oil	**Yes**
Total Installed Capacity (MW)		552.8			

APPENDIX A

Development of Additional Subcategory for Electric Generating Units Less than 100MW

TECHNICAL SUPPORT DOCUMENT

DEVELOPMENT OF ADDITIONAL SUBCATEGORY FOR ELECTRIC GENERATING UNITS LESS THAN 100 MW

Prepared for
American Public Power Association

Prepared by
RMB Consulting & Research, Inc.

August 1, 2011

EXECUTIVE SUMMARY

This report examines the technical foundation for creating a new small unit subcategory in the USEPA's proposed National Emissions Standards for Hazardous Air Pollutants for Coal- and Oil-fired Electric Utility Steam Generating Units[1] (e.g. "EGU MACT Rule"). Specifically, the small unit subcategory would apply to existing, electric generating units (EGUs) designed to fire coal with a heating value[2] greater than or equal to 8,300 Btu/lb and with a gross generating capacity of 100 MW or less (e.g. "small unit subcategory"). This investigation was sponsored by the American Public Power Association (APPA) and is intended to provide technical support for their request to EPA for a small unit subcategory in the final rule.

This investigation is limited to heat-input based (lb/mmBtu) emissions of the following hazardous air pollutants (HAPs) and HAP surrogates identified in the proposed rule, including hydrogen chloride (HCl), mercury, selected non-mercury metallic metals[3] (e.g. "total metals"), and total particulate matter[4] (TPM). RMB also includes an analysis of filterable particulate matter (FPM) due to significant interest in using this HAP as a surrogate for non-mercury metallic metals. For mercury, RMB assumes that all lignite-fired units would remain in the proposed subcategory for "Coal-fired units designed for coal < 8,300 Btu/lb".

RMB determines whether sufficient data exists within the USEPA Information Collection Request (ICR) database used in the proposed rulemaking to justify a small unit subcategory, taking into consideration any sampling bias associated with the data. RMB also investigates whether there are any statistically significant differences in emissions between small and large units, which are fundamental to establishing a small unit subcategory. Finally, RMB investigates the impact of a small unit subcategory on potential emission standards for both small units and those in the rest of the coal fleet (e.g. "large units') using the methodology in the proposed rule and several alternatives, including the methodology used in the final major source IB-MACT Rule.

The results of this investigation show that there is sufficient data within the ICR database to justify a small unit subcategory for all of the applicable HAPs and HAPs surrogate based on an analysis using the top 12% best performing units of the population. The results also show statistically significant differences in emissions between small and large units for all pollutants, which suggests that there is a fundamental benefit for a small unit subcategory. The investigation also highlights the bias in EPA's selection of the best performing units for mercury emissions in the proposed rule. EPA selected the top 12% best performing units based on the available ICR data rather than the top 12% best performing units based on the population of units, which resulted in a significantly lower proposed mercury emission standard for existing units.[5] RMB recommends that EPA address this issue in the final rule.

The Results Comparison Table summarizes the potential small unit subcategory emission standards using the analysis procedures in the proposed rule. The results show that there is a significant benefit for small units in terms of higher emission standards for HCl (0.0230 lb/mmBtu), TPM (0.060 lb/mmBtu), and total metals (0.000110 lb/mmBtu) compared with the

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[1] 75 FR 24976 (5/3/2011)
[2] Moist, mineral matter-free basis
[3] Includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, selenium
[4] Includes total filterable and condensable particulate matter
[5] Refers to subcategory for "Coal-fired unit designed for coal ≤ 8,300 Btu/lb"

proposed standards. The results show similar benefit for FPM (0.020 lb/mmBtu), should EPA implement an FPM standard in the final rule although there is significant uncertainty in these results due to limitations in the underlying dataset. For mercury, the results show no additional benefit for a small unit subcategory using the expanded pool of units based on the coal unit population. All units would be subject a potential mercury emission standard of ~ 2 lb/Btu, regardless of further size subcategorization. However, these results highlight the fact that all units would achieve equal benefit from a revised mercury analysis methodology compared with the proposed standard of 1.2 lb/TBtu.

For existing large units, the results show no change in the potential emissions standards for HCl or total metals, although the standard for TPM (0.020 lb/mBtu) is reduced from the 0.030 lb/mmBtu TPM value in the proposed rule. However, the impact of this reduction is unknown due the uncertainty in how EPA will implement surrogacy for non-mercury metallic HAPs in the final rule. Should EPA implement a filterable-only standard in the final rule, the results suggest no significant change in the potential emission standard (0.010 lb/mmBtu) for large units.

RMB did not conduct a formal impact analysis as part of this investigation, which would provide detailed fleet-wide cost impacts and estimates on overall emission reductions. In general, however, these results tend to suggest that a small unit subcategory would provide significant benefit to those EGUs less than or equal to 100 MW with minimal impact on the remainder of the fleet, based on the assumptions of an expanded mercury pool and a filterable-only surrogate for non-mercury, metallic metals. In terms of fleet-wide emissions, although the results suggest higher potential emission limits for small units for HCl and FPM relative to EPA proposed values, this may be tempered by the fact that the number of small units in the fleet contribute a relatively small fraction of total coal unit generation (refer to Appendix Table A3, 4.9%). Consequently, the development of a small unit subcategory is consistent with EPA's overall goals for reducing HAP emissions using provisions available under Section 112(d)(1).

RMB notes that there is some uncertainty in the results because of the uncertainty in how EPA will implement unit operating variability adjustments and the outcome of any "beyond the floor" evaluation in the final rule. Should EPA implement variability adjustments similar to those in the final IB-MACT rule, however, the results suggest similar benefit for a small unit category although the potential limits for all pollutants are higher than those using the EPA proposed EGU MACT methodology.

Results ComparisonTable	EGU MACT Range of 99% CI Upper Predicted Limit (UPL) Values from RMB Small Unit Subcategorization Analysis Applying Student T Test Methodology.				
	EPA Proposed Emission Standards		RMB Estimates of Emissions Standards "Full 12%" of Coal Units ≥ 8300 Btu/Lb With Small Unit Subcategory		
	Pounds per Million Btus		lbs./mmBtu	lbs./mmBtu	lbs./mmBtu
HAP	< 8300 Btu/lb (lignite)	≥ 8300 Btu/lb	≤ 100 MWs	> 100 MWs	All Units
Mercury	4.0 E-6	1.2 E-6	2.3E-06	2.1E-06	2.1E-06
			EPA's approach for using the lowest reported ICR value for a unit was applied in these calculations. RMB sensitivity analysis also considered use of average reported unit emissions and the statistical methods EPA applied for industrial boiler MACT estimates. Doing so increases emission standards relative to this table.		
Total PM (as surrogate for metals)	Same as > 8,300 Btu/lb	0.030	0.060	0.020	0.030
Filterable PM	NA	NA	0.020	0.010	0.010
Total Metal HAPS	Same as > 8,300 Btu/lb	0.000040	0.000110	0.000040	0.000040
HCl	Same as > 8,300 Btu/lb	0.0020	0.0230	0.0020	0.0020
SO2 (FGD/DSI Only)	Same as > 8,300 Btu/lb	0.2	0.2	0.2	0.2
Organics (Work Practice Standard)	Same as > 8,300 Btu/lb	Boiler Tune-Up Every 18 Months	Boiler Tune-Up Every 18 Months	Boiler Tune-Up Every 18 Months	Boiler Tune-Up Every 18 Months
Number of Coal Units	30	1061	294	767	1061
Number in EPA ICR Reporting Mercury Emissions	11	328	91	237	328
Number in Mercury HAP Best Performing 12% Calculation	2 (Hg Limit is based on "Beyond the Floor" analysis)"	40	35	92	127
Number in Non-Mercury HAP Best Performing 12% Calculation	2 (Hg Limit is based on "Beyond the Floor" analysis)"	127	35	92	127

Color Code:		
	No color	No change in Estimated Emissions Standard
	Yellow	Increased value
	Orange	Decreased Value

Note: Rounding up of emission limits was practiced by EPA for the proposed EGU MACT Rule.

APPA COMMENTARY

The American Public Power Association (APPA) is the national service organization representing the interests of the more than 2,000, not-for-profit municipal and other state and local community-owned electric utilities that collectively provide electricity to approximately 45 million Americans. These utilities, or "public power" systems, are among the most diverse of the electric utility sectors, representing utilities in small, medium and large communities in 49 states (all but Hawaii). Seventy percent of public power systems are located in cities with populations of 10,000 or less. APPA was created in 1940 as a non-profit, non-partisan organization. Its purpose is to advance the public policy interests of its members and their consumers, and to provide member services to ensure adequate, reliable electricity at a reasonable price with the proper protection of the environment. More than 90% of APPA's municipally owned utilities meet the threshold of the Small Business Regulatory Enforcement and Fairness Act (SBREFA) statute. All of APPA's municipal, state or irrigation district members are not for profit and meet the definition of the Unfunded Mandates Reform Act of 1995 (UMRA).

Overall, public power accounts for about 16% of all kilowatt-hour sales to retail electricity consumers. Approximately 46% of the megawatt hours of electricity produced by public power systems are generated using coal and more than 17% of MWH are generated using natural gas. This percentage of gas generation is growing since best practices for system stability dictate that the new intermittent resource capacity, such as wind and solar power must be backed up at a 1:1 ratio by other, non-intermittent resources.

The proposed EGU MACT rule will have a significant effect on the power industry as a whole, although these effects will be most pronounced on power providers with smaller electric generating units. In fact, many of these smaller units (≤100 MW) are peaking units that are essential for providing back up generation for intermittent wind or solar power generators or are geographically isolated and serving residential or manufacturing customers. In many cases, the estimated 93 APPA member units in the suggested small coal units category provide the only means for APPA member municipal utilities to provide for self-generation to serve their customers. EGU MACT requirements can compel retirement of such small unit self generation, in service for purposes such as preserving local municipal system reliability or to mitigate customer risks from exposure to power market price spikes during periods of heavy electricity use.

In an effort to avoid such adverse jobs, local system reliability and market price spike risks, APPA has previously commented on the need for a small unit subcategory during the EGU MACT rulemaking. In their December 2010 comments to the USEPA Small Business Review Panel, APPA states the following:

"For a source category as broad and diverse as coal- and oil-fired power plants, EPA must establish subcategories before setting MACT limits. Section 112(d)(1) allows EPA to distinguish among "classes, types and sizes of sources" in setting MACT limits. In the presentation material, EPA explains that it will evaluate a number of possible subcategorization approaches including boiler design, coal rank, unit type, oil type, and duty cycle. All of these factors are reasonable bases for subcategorization. EPA should add the size of an EGU to the list of subcategorization

approaches it considers when proposing the MACT rule. Beyond this general observation, APPA cannot provide more specific comments because of the lack of any analyses of the ICR data. However, APPA hopes to identify additional subcategorization concepts during a more detailed and effective SBREFA panel and during the official comment period after the proposed rule has been published."

This analysis is intended to provide the technical justification described above for the development of a subcategory in the final EGU MACT rule for existing EGUs with gross generating capacity less than or equal to 100 MW.

APPA believes that a small unit subcategory would provide substantial jobs, energy cost and reliability benefits, not only to APPA members, but for all utilities in the broader utility family including investor utilities, electric co-operatives, merchant power, and public power utilities with significant environmental benefits to those in the proposed rule.

OVERVIEW OF METHODOLOGY

The following section provides an overview of the scope and methodology used in this feasibility assessment of a new subcategory in the proposed EGU MACT Rule for existing, coal-fired electric generating units (EGUs)[6] with a gross generating capacity of 100 MW or less (e.g. "small unit subcategory"). The objectives of this assessment are as follows:

1. Determine whether sufficient data exists for a small unit subcategory
2. Address any potential bias issues associated with the available data
3. Determine whether there are any statistically significant differences in the emissions characteristics of small EGUs
4. Determine the impact of a small unit subcategory on potential emissions standards for small units and the other units in the coal-fleet

RMB limited the evaluation to the heat input-based emissions ('lb/mmBtu') for hydrogen chloride (HCl), mercury (Hg), total metals, total particulate matter (TPM), and filterable particulate matter (FPM). Because of the relatively large number of units that would be included in the small unit subcategory, RMB also investigated the impact on the remaining units in the fleet that are greater than 100 MW. RMB did not provide an assessment of the impact on potential SO_2 emissions standards, which may be of interest for many large EGUs equipped with flue gas desulphurization (FGD) systems. However, as a surrogate, we expect any potential effects on SO_2 to be analogous to any potential findings for HCl. In addition, we did not investigate the impact on equivalent output-based standards although we expect similar findings. RMB's evaluation is also limited to those units included in the proposed subcategory for "Coal-fired unit designed for coal ≥ 8,300 Btu/lb". Therefore, this limits the evaluation to pulverized coal (PC) and fluidized bed combustors and excludes lignite-fired units from the evaluation of mercury. Finally, although the proposed EGU MACT rule does not include a "fixed' emissions standard for FPM, there is significant interest in developing such a standard from various parties and this information was intended to assist in such an evaluation.

[6] "EGU" is defined as a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale.

RMB utilized the data provided in the latest versions[7] of EPA's MACT floor analysis spreadsheets, which are derived from the 2010 Information Collection Request (ICR) for the EGU MACT rulemaking. The mercury data was supplemented with the most recent data release by EPA.[8] RMB is aware of potential data quality issues in the dataset, although this analysis is based on the reported values with no attempts made to correct spurious data. RMB believes that the floor analysis (for a small unit subcategory or otherwise) would significantly benefit from a thorough review of the data.

The floor analysis procedures used in the evaluation primarily follow those utilized by EPA in the proposed rulemaking. However, RMB also investigated other methods of addressing unit operating variability, including the statistical "upper prediction limit" (UPL) that was used in the recently promulgated Industrial Boiler MACT (IB-MACT) Rule. In addition, because EPA's recent ICR supplement provided a relatively complete dataset for mercury, RMB also investigated other floor analysis methodologies and the impact on the UPL-adjusted values.

DATA SAMPLING BIASES

Small and Large EGU Population Samples

Because the proposed EGU MACT standards are based on the entire population of coal-fired units regardless of size, the data utilized for this evaluation were adjusted to properly reflect the population of coal-fired EGUs less than 100 MW in the coal fleet. The most recently available EIA data[9] suggests that the population of coal-fired EGUs less than 100 MW is 297 units. This represents approximately 27% of all coal-fired EGUs based on EPA's assumption of 1,091 applicable coal-fired units in the fleet. A fleet total of 1,091 units minus 297 results in 794 units (73%) greater than 100 MW.

As specified in Section 112(d) of the Clean Air Act (CAA), the emissions standards for existing unit subcategories should be no less stringent than the average emissions of the best performing 12 percent of the existing sources for which EPA has emissions information. The population of EGUs less than 100 MW suggests that the emissions floor analysis should be conducted using data from the best performing 35 units. For the remaining units (> 100 MW), the data suggests that the emissions floor analysis should be conducted using data from the best performing 95 units. For mercury, RMB adjusted the sample size (92 units) based on the assumption that lignite-fired units would remain under the existing subcategory in the proposed rule for "Coal-fired unit designed for coal < 8,300 Btu/lb".[10]

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[7] Latest spreadsheet versions for HCl and PM are dated March 16, 2011 and the latest Hg spreadsheet version is dated May 18, 2011. Copies of the spreadsheets are available on the EPA Utility MACT website (http://www.epa.gov/ttn/atw/utility/utilitypg.html).

[8] The complete Part II/Part III data set for mercury in spreadsheet format (dated June 30, 2011) is available on the EPA Utility MACT website (http://www.epa.gov/ttn/atw/utility/utilitypg.html).

[9] Energy Information Agency Form EIA-860, "Annual Electric Generator Report" (12/31/2008)

[10] The pool is reduced to 1061 units for units >100 MW for mercury.

Biases in ICR Data Population

The 2010 ICR data is based on a composite of "Part II" and "Part III" data, which presents a potential bias in the evaluation due to differences in the sample size between the two groups and the manner in which the units were identified. The Part II data consists of historical emissions test data that were submitted by those units that had conducted stack sampling for one or more of the various pollutants within above five years of the ICR.[11] The Part III data represents EPA's assessment of the top 15% of the best performing units in the fleet for each pollutant. These units were selected based on the type and age of installed control equipment. EPA also included a subset of 50 coal-fired units that were randomly selected ("Random 50") for Part III emissions testing, which was intended to assist EPA in evaluating the impact of the regulations on the remaining coal fleet.

In order to determine whether sufficient data exists for the development of both a small and large unit subcategory, RMB estimated the total number of available "best performing units" based on a weighted combination of the available data taking into consideration the above sampling bias. RMB included all those units identified for Part III (non-Random 50) testing as "best performers" in the respective subsets for each pollutant. For those pollutants where the available number of Part III (non-Random 50) units did not meet the required minimum number of "best performing" units for the floor analysis, RMB included additional "best performing" units based on 12% of the combination of Random 50 and Part II data, with some adjustments made for Random 50 bias as noted below. This approach is consistent with the statutory definition of "best performing" units because the Random 50 and Part II data represent a random sample of the population of units. Our findings suggest that, with the exception of TPM[12], the database contains a sufficient number of best performing units for all pollutants for both small and large unit subcategories (see Tables A1 and A2 in the Appendix). Therefore, the development of the small unit subcategory can be supported with the available data based on the top 12% of the population of units.

RMB notes that the above discussion provides a practical assessment of whether there is a sufficient number of the best performing units in the database, which is fundamental to supporting the small unit subcategory. However, because of potential biases in measured emissions for the various sources of data, the emissions floor analyses for this assessment were performed utilizing the top 12% of all data for each pollutant regardless of whether the data was obtained under Part II or Part III. This is similar to the approach utilized by EPA in the proposed rulemaking.

[11] Specifically, EPA's Section 114 letters requested utility respondents to provide all emission test data for all units conducted since January 1, 2005.

[12] The EPA spreadsheets appear to be missing at least six Part III (non-Random 50) datasets for TPM for those units included in the RMB floor analysis for small units. Including these additional datasets shows that there are at least 35 best performing units for TPM.

Bias in Mercury Pool Selection

In the supporting statement that accompanied the EGU ICR[13], the EPA described how it specifically selected sources for Part III mercury testing with the "newest PM controls" that it believed to represent the best PM performers. As a result, the tested units included many sources with high efficiency fabric filter baghouses and a number of sources with activated carbon injection, both of which tend to provide higher levels of mercury removal. These new PM sources would also tend to have other new high efficiency NO_X and SO_2 controls that can also have an impact on mercury.

In the proposed rulemaking, EPA based the mercury standard on the top 12% of the reported data (40 units) rather than the top 12% of the population of units, as they did for all the other pollutants. In the preamble, EPA justified this approach by stating that "we did not believe those units represented the top performing 12 percent of sources for Hg in the category at the time we issued the ICR and we made no assertions to that effect." However, the data suggest that EPA clearly selected units that would profile as likely to be among the best performers for mercury. While representing only about half of the mercury test sources in EPA's database, the overwhelming majority of the lowest 128 mercury test results[14] came from the ICR test sites identified by EPA to be among the best performing units. The resulting bias in EPA's sample selection suggests that the proposed mercury standard is based on the top 4% of all units, rather than the top 12%, which is obviously inconsistent with Section 112 of the CAA. In order to resolve this bias in the final rule, EPA should apply the same technique for mercury that it used for all other pollutants.

This issue is also relevant in the development of a small unit subcategory. For this evaluation, RMB has assumed that all Part III data (excluding any Random 50 units) represents the top 15% of the best performing units for large and small units based on the respective sample populations rather than as a percentage of reported data.

Bias in Random 50 Selection

RMB investigated the potential bias in the emissions data from any of the Random 50 units that were included in the pool of available units for each subcategory. RMB compared the lowest "achieved" emissions level for each Random 50 unit with the maximum "achieved" emissions level for the other Part III (non-Random 50) units within each pool. Any Random 50 unit with emissions less than the maximum emissions level based on the Part III (non-Random 50) units was considered a best performer and removed from the random component in the estimate of additional best performers in the Part II/Random 50 data. As shown in Tables A1 and A2 in the Appendix, the data suggest a significant potential bias in the selection of the Random 50 units based on the lowest reported emissions.

[13] Part B of Supporting Statement for OMB Review of EPA ICR No. 2362.01 (OMB Control Number 2060-0631): Information Collection Effort for New and Existing Coal- and Oil-fired Electric Utility Steam Generating Units

[14] Given a total population of 1061 existing sources, 128 represents 12% of the coal-fired (non-lignite) sources that would be used for the existing unit floor analysis.

EMISSIONS CHARACTERISTICS OF SMALL EGUs

In order for a small unit subcategory to be meaningful, the data should fundamentally demonstrate statistically significant differences in the average emissions for units less than 100 MW when compared with units greater than 100 MW. In this evaluation, RMB compared the emissions of the best performing small and large units for the various pollutants to determine statistical significance of any differences in the reported emissions between the two sample sets. RMB determined sample distribution normality based on a single sample Komolgorov-Smirnov (K-S) test. For each pollutant, the student t-test was used to determine statistical significance of the differences in the average unadjusted floor values between the small and large units where the distributions were the same. For any case in which the distribution was highly skewed or the distributions were not the same, the t-test could not be applied. Instead, RMB applied the two sample K-S test to determine whether the distributions and average values were indeed different.

Table 1 shows a comparison of the average emissions for small and large units for each pollutant. The data show that emissions for small units are significantly higher than large units for each pollutant, particularly for HCl[15]. The data also show that the observed differences are considered statistically significant for each pollutant, which suggests that there should be some benefit to further subcategorization of units less than 100 MW.

Table 1 - Comparison of Average Emissions for Each Pollutant (lb/mmBtu)

	Average Emissions [lb/mmBtu]			Distribution (KS)	
Pollutant	**≤100 MW**	**>100 MW**	**Variation (abs %)**	**<100 MW**	**>100 MW**
HCl	5.09E-03	1.68E-04	2941%	Log	Log
Hg (all/no lignite)	5.46E-07	2.17E-07	151%	Log	Log
TPM	2.19E-02	9.70E-03	126%	Log	Normal
FPM	4.63E-03	1.75E-03	165%	Log	Normal
Total Metals	2.91E-05	1.26E-05	132%	Log	Log

IMPACT ON POTENTIAL EMISSIONS STANDARDS

The potential benefit for small units and fleet impacts are ultimately determined by changes in the emissions standards. RMB cannot provide a definitive assessment of potential emissions standards because there is significant uncertainty in the procedures that EPA will ultimately use in the final rule to address unit operating variability[16] [17] as well as the potential impact of a "beyond the floor" evaluation. However, because the analysis is focused on the methodology used in the proposed rulemaking these results can provide a conservative prediction of emissions

[15] RMB notes that the HCl results may indicate a bias in the coal supply for small units.

[16] In determining emissions standards, an adjustment factor is applied to the emissions floor values for each pollutant that, in theory, accounts for emissions variability due to typical operations, fuel-related variability, and variability due to measurement uncertainty.

[17] In the proposed rule, EPA accounted for variability by determining the emissions standards based a statistical adjustment of the emissions floor values known as the 99% upper prediction limit (UPL).

standards for small and large units. Furthermore, this analysis is useful in highlighting the relative differences in the potential emissions standards between small and large units under various floor analysis methodologies.

Our review of EPA's MACT floor analysis shows significant technical flaws in their approach. In the final rule, it is possible that EPA may implement many of the floor analysis procedures used in the recently finalized Industrial Boiler MACT Rule (IB-MACT), which included a more representative method of calculating statistical variability and, in some cases, additional adjustments for fuel-related variability.[18] Although the IB-MACT approach has limitations, RMB considers it more technically valid than the approach utilized in the proposed EGU MACT rulemaking.

EPA Methodology – Proposed MACT Rule

RMB estimated potential emissions standards for small and large units based on the procedures used by EPA in the floor analysis of the proposed rule ("EPA proposed methodology") with adjustment for bias in the selection of best performing units for mercury. For most pollutants, the EPA proposed methodology establishes the pool of units in each emissions floor analysis ("pool determinate") using the top 12% of the population of units based on the lowest reported test result for each unit. The unadjusted emissions floor is then calculated based on the average of the lowest reported test result for each unit for all units within the pool. Finally, the adjusted emissions floor is determined based on a 99% confidence UPL ("99% UPL"), assuming a normal distribution of the underlying dataset. In this analysis RMB presumes that the UPL value represents the final emissions limit with adjustment for rounding, although that value could be further adjusted based on a "beyond the floor" evaluation.

Tables 2 and 3 summarize the 99% UPL values and potential emissions standards, respectively, for each pollutant using the EPA proposed methodology. The baseline case represents the UPL values and proposed emissions standard for all pollutants (except for mercury) assuming no subcategorization for small units. For mercury, the baseline case represents the equivalent UPL and potential emissions standard using the revised pool of best performing units (based on the top 12% of the population). The potentials emissions standards in shown Table 3 are based on the rounding conventions in the proposed rule.

[18] Other industry groups are currently investigating variability adjustments based on CEMS data. It is possible that EPA could utilize such an alternative or in combination with UPL adjustments in the final rule.

Table 2 – Comparison of 99% UPL Adjusted Floor Values (Normal T-Test)

	99% UPL Values [lb/mmBtu]			Baseline Difference	
Pollutant	**Baseline**	**≤100 MW**	**>100 MW**	**≤100 MW**	**>100 MW**
HCl	1.2E-03	2.3E-02	1.2E-03	1728%	0%
Hg (12% of population, no lignite)	2.1E-06	2.2E-06	2.1E-06	6%	1%
TPM	2.6E-02	5.5E-02	2.0E-02	111%	-24%
FPM	7.7E-03	1.2E-02	4.1E-03	56%	-47%
Total Metals	3.8E-05	1.1E-04	3.3E-05	190%	-13%

Table 3 – Comparison of Potential Emissions Standards (99% UPL, Normal T-Test)

	99% UPL Values [lb/mmBtu]			Baseline Difference	
Pollutant	**Baseline**	**≤100 MW**	**>100 MW**	**≤100 MW**	**>100 MW**
HCl	0.0020	0.0230	0.0020	1050%	0%
Hg (12% of population, no lignite)	2.1E-6	2.3E-6	2.1E-6	10%	0%
TPM	0.030	0.060	0.020	100%	-33%
FPM	0.010	0.020	0.010	100%	0%
Total Metals	0.000040	0.000110	0.000040	175%	0%

The results show a significant increase in the UPL and potential emissions standards for HCl and PM for small units. For large units, the analysis shows minimal change in the UPL but no change in the potential emissions standard for HCL. The data also show some reduction in the UPL for TPM, FPM, and total metals although this results is no change in the potential emissions standard for total metals but a significant reduction in the potential emissions standard for TPM. For FPM, the results show a significant reduction in the UPL but a negligible change in the potential emissions limit. Finally, the analysis shows no significant change in UPL or the potential emissions standard for mercury using the revised pool of best performing units although the results clearly show in increase for all units (including the baseline) using the revised methodology.

Bhaumik and Gibbons Log-Normal UPL Alternative

As noted earlier, there is significant uncertainty in the methodology that will be used in the final rule to address unit operating variability. Even assuming that EPA will continue to apply the UPL methodology, there are a number of variables that can have significant effects on the calculated UPL value. Such variables include the pool determinate method (i.e. minimum or average test values), variance determination method (i.e. test runs or test averages), UPL confidence level (i.e. 99% or 99.5%), and UPL methodology (i.e. based on actual distribution or assume normality). One of the most significant deficiencies in the floor analysis of the proposed rule is the UPL methodology. EPA applied the student t-test for estimating the UPL based on the assumption that all datasets could be treated as having a normal distribution. To justify the normality assumption, EPA cited the Central Limit Theorem which states that the distribution of independent *random* values will continue to better approximate a normal distribution as the sample size grows. In this case, EPA's assumption is flawed because the consecutive test runs

on the ICR units are not independent values and the data are not random because EPA pre-selected the best performing units. In the final rule RMB recommends an approach similar to the one taken in the final IB-MACT Rule, where the UPL methodology is based on the actual distribution of each dataset as determined by the simplified skewness and kurtosis tests or other, more robust techniques. For log-normal approximated datasets, RMB further recommends the methodology specified by Bhaumik and Gibbons (2004) ("B&G Log UPL") for estimating the UPL based on the arithmetic mean.

RMB investigated the impact of the B&G Log UPL methodology on the potential emissions standards with a small unit subcategory. As shown in Table 4, the results suggest that the emissions standards for the baseline case and the small/large unit subcategories would be significantly higher than the proposed standards for all pollutants with a similar benefit for the small unit subcategory. RMB notes that the results show several spurious values, which suggests further investigation of the B&G approach is necessary for highly skewed or log-normal "approximated" data distributions. In these cases, application of the log t-test approach used in the proposed IB-MACT Rule may be warranted.

Table 4 – Comparison of 99% UPL Adjusted Floor Values (B&G Log Approach)

	99% UPL Values [lb/mmBtu]			Baseline Difference	
Pollutant	**Baseline**	**≤100 MW**	**>100 MW**	**≤100 MW**	**>100 MW**
HCl	1.7E-03	4.8E-01	1.3E-03	27883%	-27%
Hg (12% of population, no lignite)	6.7E-06	2.1E-05	7.1E-06	206%	5%
TPM	8.3E-06	9.8E-02	NA	1178358%	NA
FPM	3.5E-02	3.7E-02	NA	8%	NA
Total Metals	6.9E-05	2.1E-04	5.9E-05	198%	-14%

Alternative Floor Analysis Methodologies (Mercury Only)

RMB investigated two alternative floor analysis scenarios for mercury with the EPA proposed approach using the 99% UPL (student t-test) based on the assumption of a normally distributed dataset. The analysis also assumes the top 12% best performing units based on the sample population, excluding lignite-fired units.[19] These alternatives are intended to demonstrate the effects of variations in the pool determinate and the average value used to calculate the UPL value. This analysis is limited to mercury because all the Phase II test data was not readily available[20] for a similar analysis for the other pollutants.

Under 'Scenario 1', the pool of best performing units represents the top 12% of the unit population based on the minimum reported test average for each unit, which is the same pool determinate method used in EPA's proposed methodology. The average value used to determine the UPL[21] is based on the mean of the reported test averages for each unit in the pool. Under

[19] The sample populations for this analysis are as follows: Baseline (127), ≤100 MW (35), >100 MW (92)
[20] All Phase II data is presumably contained in the EPA ICR database but was unavailable in EPA's floor analysis spreadsheets for the existing unit floor analysis.
[21] This average value is referred to as "X-bar" in the UPL calculation using EPA's floor analysis spreadsheets.

'Scenario 2', the pool of best performing units represents the top 12% of the unit population based on the average reported test for each unit. The average value used to determine the UPL is based on the mean of the reported test averages for each unit in the pool. All other calculation procedures for both scenarios follow EPA's proposed methodology. Notwithstanding earlier discussions on the arbitrary assumption of normality, we consider these two scenarios to be more logical variants of EPA's proposed methodology.

Table 5 shows a comparison of the two scenarios with the EPA proposed methodology for the small and large unit subcategories using the expanded mercury pool. The baseline case demonstrates the effects of the alternative methodologies assuming no small unit subcategory. The results show similar UPL values for both the baseline and the small unit subcategory (~ 2 lb/TBtu) for both alternative scenarios. For the large units, the results show no significant change in the UPL using the EPA proposed methodology or Scenario 1, although the UPL decreases significantly from the baseline case (~1.4 lb/TBtu) for Scenario 2. That the UPL for all scenarios is greater than the UPL in the proposed rule results primarily from the expanded pool of best performing units rather than the adjustments to the pool determinate or the average value used in the UPL calculation.

Table 5 - Alternative Floor Analysis Methodologies for Mercury (99% UPL, Normal t-Test, Expanded Pool)

Scenario	99% UPL Values [lb/mmBtu]			Baseline Difference	
	Baseline	≤100 MW	>100 MW	≤100 MW	>100 MW
Proposed Rule (40 best performers)	1.2E-6				
EPA (expanded Pool)	2.1E-06	2.2E-06	2.1E-06	6%	1%
Scenario 1	2.2E-06	2.3E-06	2.3E-06	4%	0%
Scenario 2	2.2E-06	2.1E-06	1.4E-06	-5%	-36%

RMB also investigated the effects of applying higher confidence levels to the estimated UPL values for mercury based on the expanded mercury pool using the t-test approach (normal distribution) as shown in Table 6. EPA assumed a confidence level of 99% for the proposed rulemaking. This confidence level has been used in other MACT rulemaking although RMB could find no further justification in the preamble or EPA's floor analysis for this value.

Table 6 – Effect of UPL Confidence on Mercury UPL Values (Normal t-Test, Expanded Pool)

	UPL Values [lb/mmBtu]		
Confidence	**Baseline**	**≤100 MW**	**>100 MW**
99.0%	2.1E-06	2.2E-06	2.1E-06
99.5%	2.3E-06	2.4E-06	2.3E-06
99.9%	2.7E-06	2.8E-06	2.7E-06

IMPACT ON FLEET-WIDE EMISSONS

A formal impact analysis for an existing, small unit subcategory, which would provide a detailed assessment of fleet-wide implementation costs and the effects of overall emissions, was beyond the scope of this evaluation. However, the results of this investigation provide some useful findings on the overall impact on the fleet in broad terms.[22]

Mercury Impacts

Using the EPA proposed methodology with the expanded mercury pool, the results suggest that the small unit subcategory would likely have no significant impact on the fleet or fleet-wide mercury emissions. Although the subcategory would provide no marginal benefit for small units, the expanded pool would provide the same benefit for all units across the fleet compared with the proposed rule.

HCl Impacts

For HCl, the data suggests a significant benefit for small units with minimal impact on the larger units in the fleet using the EPA proposed methodology. RMB notes that, given EPA's reluctance to establish a health-based emission limit (HBEL) for HCl, the small unit subcategory could provide comparable benefit for small units.

TSM/Total Metals Impacts

For TSM and total metals, the impact is more difficult to assess due to the uncertainty in how EPA will implement surrogacy for non-mercury, metallic HAPs in the final rule. RMB also cautions against definitive conclusions regarding TPM, FPM, and total metals based on this analysis due to the limitations in the available data.[23]

RMB and others have argued in comments on the proposed rule that a filterable-only emission standard is a valid surrogate for non-mercury, metallic HAPs (including selenium) and that a TPM standard provides no further compliance benefit for this type of HAP. Assuming EPA implements a filterable-only emission standard in the final rule, the results show a significant

[22] These observations may not be completely accurate due to co-benefits of the various control technologies.
[23] Recall, RMB's analysis is based on the latest versions of EPA's floor analysis spreadsheet, which do not include all of the Part II data for PM. Given that there is likely a substantial amount of Phase II data that would be included in a revised floor analysis, this could significantly affect the variability adjustments using the UPL methodology.

increase in the potential emissions limit for small units. However, this finding does not necessarily suggest a corresponding benefit for small units. While many units would undoubtedly benefit from a higher FPM limit, the magnitude of benefit is ultimately determined based upon an existing unit's need for and type of retrofit PM control. For example, an existing, small unit with current FPM emissions that exceeded 0.03 lb/mmBtu (baseline) that decided to install a baghouse would likely achieve PM emissions less than 0.02 lb/mmBtu (potential small unit FPM emissions standard) after the retrofit regardless. In this case, the subcategory would provide no real benefit for the unit. Conversely, many existing ESP-equipped units may elect to comply with a small unit FPM standard through equipment upgrades. In this case, the subcategory would provide significant benefit.

CONCLUSIONS

1. EPA proposed methodology for selecting the best performing mercury units based on the top 12% of units in the available data is flawed and results in proposed emissions standards that are significantly biased low – representing the top 4% of the population of units. In the final rule, EPA should revise the floor analysis for mercury to reflect the top 12% of units based on the entire population as they have done for the other pollutants.

2. EPA's method of addressing unit operating variability contains significant flaws, underestimates variability, and is inconsistent with the approach they have implemented in the final IB-MACT Rule.

3. There is sufficient data available in the ICR database to support the development of a small unit subcategory (≤ 100 MW) based on the best performing top 12% of units in the coal-fired EGU population.

4. For the HAPs under investigation (HCl, Hg, TPM, FPM, Total Metals), the data show that emissions between small (≤100 MW) and large EGUs (>100 MW) are statistically significant, which suggests that some fundamental benefit could be achieved by a new subcategory for small units.

5. The results show significant increases in the UPLs and the potential emissions standards for HCl (0.0230 lb/mmBtu), TPM (0.060 lb/mmBtu), and FPM (0.02 lb/mmBtu) for small units based on the EPA proposed methodology. Because the need for acid gas control and fabric filter baghouses will be driving factors in many cases for the retirement of small affected units, these results suggest that significant benefit can be achieved by a new subcategory for small units.

6. The results show minimal change in the UPL and no change in the potential emissions standard for HCl (0.0020 lb/mmBtu) for large units based on the EPA proposed methodology. RMB did not investigate the effects on the potential emissions standard for SO_2 but expects similar findings.

7. The results show some reduction in the UPL values for TPM (24%), FPM (47%), and total metals (13%) for large units based on the EPA proposed methodology. However,

there is negligible change in the potential emissions standard for FPM (0.010 lb/mmBtu) and total metals (0.000040 lb/mmBtu) and a 33% reduction in the potential emission standard for TPM (0.020 lb/mmBtu). While this represents a significant reduction in the TPM standard, the impact on the large unit fleet is uncertain because of the uncertainty in how EPA will address surrogacy for non-mercury, metallic HAPs in the final rule.

8. The results show no significant change in the UPL or the potential emissions standard for Hg for small or large units (~2 lb/TBtu) based on the EPA proposed methodology with the expanded pool of units based on the top 12% of the population. Although this finding does not suggest any marginal benefit for a small unit subcategory for this pollutant, the expanded pool shows that all units will achieve an equal but substantial benefit using the revised floor analysis approach.

9. In order for small units to achieve the full benefit of a small unit subcategory, EPA will need to revise the approach used to select the best performing mercury units in the final rule.

10. The expanded analysis for mercury using the 99% UPL based on the assumption of normality for all data distributions shows that using the mean of average test results for all units in the pool to determine the UPL (Scenario 1) has no significant effect on the UPL value (~ 2 lb/TBtu). The analysis also shows that using the average emissions to determine the pool and the mean of test results for all units in the pool to determine the UPL (Scenario 2) has no significant effect on the UPL value for the baseline or the small unit cases (~2 lb/TBtu), although it results in significant reduction in the UPL for large units (~1.4 lb/TBtu).

11. Overall, subcategorization provides the same or additional benefit for small units compared with the baseline scenario, regardless of the UPL methodologies that were evaluated, although the magnitude of this benefit and the impacts for the rest of the fleet will depend on the variability adjustment procedures and the outcome of any "beyond the floor" evaluation in the final rule.

APPENDIX

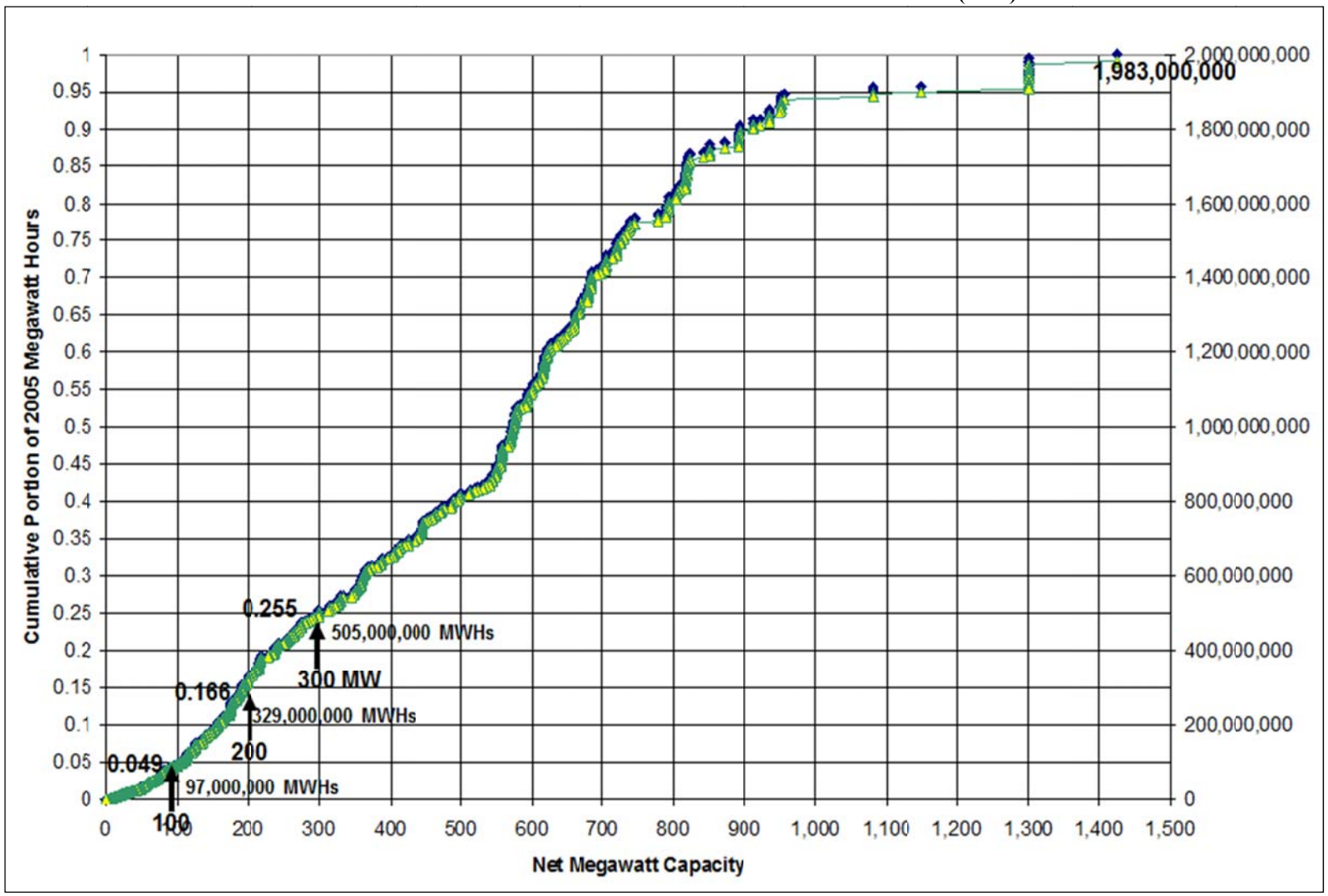
Table A1 – Breakdown of Available Data in EPA Floor Analysis Spreadsheets for "Small" Unit Subcategory (≤100 MW)

Pollutant	Total Part II/Part III Sample Size	Part III Units					Part II Units (Excl. Part III Units)	Floor Count ("Best Performers")		
		Total	Excl. Random 50	Random 50 Units				Part III (excl. R50)	Top 12% (Part II + R50)	Total
				EPA	Excl. Best Perf.	Total (RMB)				
Hg (top 12% population)	91	41	39	15	13	2	50	39	7	46
HCl	52	39	35	13	9	4	13	35	3	38
TPM	59	34	29	12	7	5	25	29	4	33
FPM	112	41	37	14	10	4	71	37	9	46
TSM	44	44	41	15	12	3	0	41	1	42

Table A2 – Breakdown of Available Data in EPA Floor Analysis Spreadsheets for "Large" Unit Subcategory (>100 MW)

Pollutant	Total Part II/Part III Sample Size	Part III Units					Part II Units (Excl. Part III Units)	Floor Count ("Best Performers")		
		Total	Excl. Random 50	Random 50 Units				Part III (excl. R50)	Top 12% (Part II + R50)	Total
				EPA	Excl. Best Perf.	Total (RMB)				
Hg (top 12% population)	197	154	153	24	23	1	43	153	6	159
HCl	204	182	182	26	26	0	22	182	3	185
TPM	186	134	133	19	18	1	52	133	7	140
FPM	434	170	167	25	22	3	264	167	33	200
TSM	176	176	175	26	25	1	0	175	1	176

Table A3 – Unit Size Contribution to Annual Coal Fleet Generation (2005)



APPENDIX E

APPA's Comments to U.S. EPA and SBA regarding EGU MACT (and pointing out the benefits of using GACT to reduce regulatory costs and burdens) – December 2, 2010

Small Business Review Panel for EPA's Rulemaking for Hazardous Air Pollutant Emissions from Coal- and Oil-Fired Electric Utility Steam Generating Units

What is APPA

The American Public Power Association (APPA) is the national service organization representing the interests of the more than 2,000, not-for-profit municipal and other state and local community-owned electric utilities that collectively provide electricity to approximately 45 million Americans. These utilities, or "public power" systems, are among the most diverse of the electric utility sectors, representing utilities in small, medium and large communities in 49 states (all but Hawaii). Seventy percent of public power systems are located in cities with populations of 10,000 or less. APPA was created in 1940 as a non-profit, non-partisan organization. Its purpose is to advance the public policy interests of its members and their consumers, and to provide member services to ensure adequate, reliable electricity at a reasonable price with the proper protection of the environment.

Overall, public power accounts for about 16 percent of all kilowatt-hour sales to retail electricity consumers. Approximately 46% of the megawatt hours of electricity produced by public power systems are generated using coal. Moreover, more than 90% of public power utility systems meet the definition and qualify as small businesses under the Small Business Act and the Small Business Regulatory Enforcement and Fairness Act of 1996 (SBREFA).

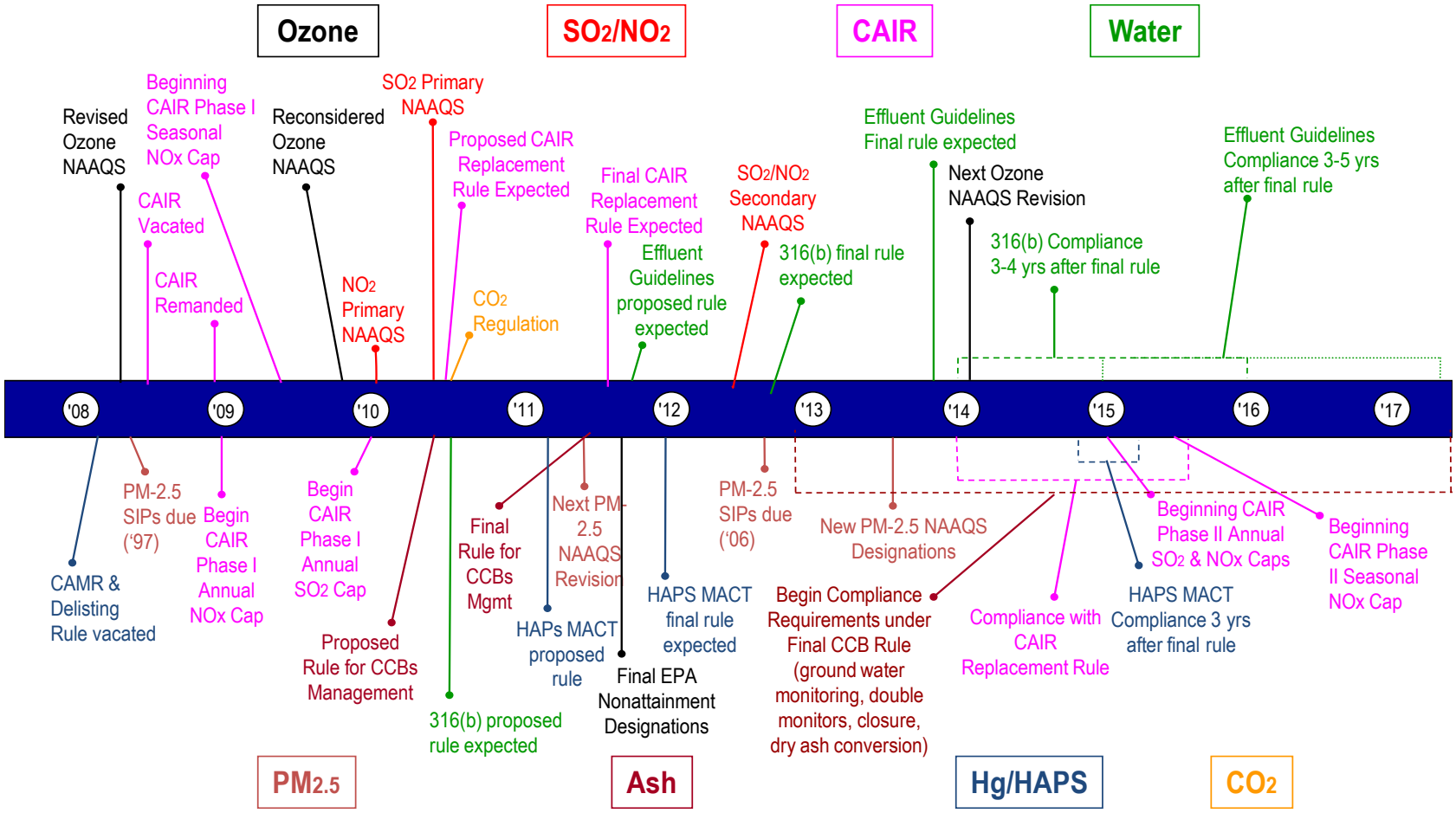
The significance of the EGU MACT standard

There are many environmental regulations hitting the utility sector in a window roughly bounded by 2014-2020 that require enormous investments, retirements, capital expenditures, and the raising of financial requirements through both cash and bonds at municipal public power utilities. These investments cannot be underestimated. Nor can the reliability issues be underestimated. It has been estimated by many that anywhere from 30-50% of the remaining coal-fired power plants might make the decision to close those coal fired plants due to the

combination of MACT standards (likely requiring many control technologies) and scrubbers required by 2014 in many of the 31 states covered by Regional Transport (RT) rule's inadequate state allocations. These regulations will also be amidst a series of tighter ozone, PM 2.5, SO_2, NOx, and the new regulations for NSPS for Greenhouse gases (including CO_2, methane, and SF^6). Additionally, many power plants will face tighter controls for various water pollutants and possibly cooling towers to minimize aquatic organism harms from intake structures. These are best exemplified in the following diagram. These do not include other investments by power plants such as EPA regulations such as Toxic Substances Control Act (or TSCA) reporting, PCB phase out, transformer replacement and NERC's costly and time-consuming reliability standards.

Given the importance of these regulations, it is all the more important that the SBREFA SER panel for utility MACT (oil and coal) be thorough, thoughtful and valuable to the EPA, OMB and to the industry that SBREFA is designed to affect.

Possible Timeline for Environmental Regulatory Requirements for the Utility Industry



-- adapted from Wegman (EPA 2003) Updated 2.15.10

The American Public Power Association and its members appreciate the opportunity to participate in the small business review panel for EPA's rulemaking to set maximum achievable control technology (MACT) standards for hazardous air pollutant (HAP) emissions from coal- and oil-fired electric utility steam generating units (EGUs) through this panel convened under the Small Business Regulatory Enforcement Fairness Act of 1996 (or a SBREFA SER panel). APPA has been designated a "viewer" and many of the panel members are from public power utilities across the country.

The EGU MACT rulemaking has the potential to be one of the most expensive rulemakings the utility industry has ever faced. Its impact on APPA's smaller members could be enormous, forcing them either to install extensive new pollution control equipment or even to close certain units. As set out in the statute, EPA must carefully consider the impact its EGU MACT rule will have on small entities and must act to lessen the burden of that rule on those entities.

The Small Business Regulatory Fairness Act (SBREFA) was enacted by Congress to provide small entities a meaningful voice in major federal rulemakings. Among the Act's goals are to encourage the "effective participation" of small business in the federal regulatory process[1] and to create a more cooperative regulatory environment among agencies and small businesses that is less punitive and more solution oriented.[2] Section 609 of SBREFA envisions that small business panels will review "any material the agency has prepared in connection with this chapter" including information required to be part of the initial regulatory flexibility analysis.[3] A regulatory flexibility analysis typically includes descriptions of significant alternatives to the proposed rule, differing compliance or reporting requirements or timetables that take into account the resources available to small entities, and the clarification, consolidation, or simplification of compliance and reporting requirements for small entities.[4] **This SER meeting involved no preparation and distribution of these clarifications, consolidations or simplifications of the EPA regulatory options by the EPA.**

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[1] 5 U.S.C. § 203(3).

[2] 5 U.S.C. § 203(6).

[3] 5 U.S.C. § 609(b)(4); *see also* 5 U.S.C. § 603(b)(3), (4) and (5) and 603(c).

[4] *See* 5 U.S.C. § 603(c).

The highly abbreviated nature of this particular small business review panel that has been established for the EGU MACT rule prevents small APPA members from having the meaningful advisory role contemplated by SBREFA.[5] Only one panel meeting was provided and after that meeting, panel members were given a mere 14 days to prepare written comments.[6] The materials provided by EPA just prior to the only panel meeting are little more than what the Agency typically offers in a notice of proposed rulemaking. This is not consistent with the three prior SBREFA SER panel meetings on other proposed regulations where APPA was invited to participate. Those included the Clean Water Act Section 316 (b) cooling water intake structures/entrainment and impingement of aquatic organisms, the ICI Boiler MACT rulemaking in 2003 (for <25 MW utilities) and others held in the last ten years where the APPA has been invited to attend and participate. This SER panel meeting held on Dec. 2, 2010 was slightly more consistent with the very unorthodox small entity outreach on the GHG Tailoring rule in 2009. APPA accepted the non-SER panel approach on GHG because of the unusual circumstances surrounding how CO_2 would be regulated and the cascade of regulatory actions following the CO_2 reductions from the Section 202 of the Clean Air Act for tailpipe standards onto the regulated stationary sources of industry. **However the EGU MACT HAPs regulation and the timing of that regulation required no truncated or shortened process for the SER panel**. **APPA believes that this one meeting makes a mockery of the productive goals of SBREFA and the SER panel process that have been so successful in identification of regulatory options in other programs**.

On this EGU MACT rulemaking the EPA materials did not include possible rulemaking alternatives nor any information about possible compliance or reporting options. Moreover, the material lacked any results of EPA's analyses of the data from the extensive information

[5] The presentation materials suggest that EPA was required to foreshorten the small business review process because it is under a consent decree which sets a tight schedule for the EGU MACT rulemaking. *See* Slide 8. However, the SBREFA review process is an important part of any major federal rulemaking. EPA should have factored that process into any rulemaking schedule it agreed to and defended before a federal district court judge. As a practical matter, the consent decree allows EPA to unilaterally return to the judge to request additional time to complete the EGU MACT rulemaking. If EPA feels so constrained by the consent decree that it cannot provide an adequate SBREFA review process, then it should ask the judge for a schedule extension.

[6] While providing only 14 days for written comments by panel participants, EPA nevertheless propounds six slides of questions for those entities. Many of those questions were answered by all EGUs in response to Parts 1 and 2 of the EGU MACT ICR. Others would require far more than 14 days to provide meaningful responses. If EPA is serious about wanting input on the questions it posed to panel members, then a much longer comment period should be provided.

collection request (ICR) that EPA identified as being critical to the promulgation of an EGU MACT rule**. As a result of the poor and inadequate preparation by the U.S. EPA and failing to meet the statutory requirements, APPA can offer only general comments on EGU MACT rulemaking in these comments.**

APPA urges that additional small business SER panel meetings be held following a better staff review of the data and that small entities (including all of those on this panel) be given the opportunity to comment on real regulatory alternatives once EPA reaches that point in its rulemaking process. APPA would be pleased to participate in that process.

General Comments on the EGU MACT Rulemaking

1. EPA failed to correctly identify the scope of the HAPs to be regulated

At several places in the presentation material, EPA indicates that it *must* set emission standards that address all HAPs emitted from EGUs.[7] This conclusion is legally incorrect. EGUs are treated uniquely under § 112 of the Clean Air Act (CAA). Section 112(n)(1)(A) requires EPA to study the hazards to public health reasonably anticipated to occur as a result of emissions from EGUs "after the imposition of the other requirements of the CAA." After considering the results of that study, the EPA Administrator must then decide if further regulation is "appropriate and necessary." EPA completed the EPA Utility Study in February 1998. In December 2000, the EPA Administrator found that regulation of coal- and oil-fired EGUs was appropriate and necessary under § 112 and proceeded to list those units under § 112(c).[8] EPA's notice of regulatory finding focused solely on the risks to public health posed by mercury emissions from coal-fired power plants. Because § 112(n)(1)(A) requires a predicate health finding before EPA can regulate EGUs under § 112, EPA's December 2000 regulatory determination only gave it authority to set MACT limits for mercury emissions from EGUs.

When EPA first proposed MACT limits for EGUs in 2004, it went to great lengths to explain why it only had legal authority to set mercury MACT limits for coal-fired EGUs.[9]

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[7] *See* Slides 9 and 13.

[8] 65 Fed. Reg. 79,825 (Dec. 20, 2000).

[9] *See* 69 Fed. Reg. 4,659-61 (Jan. 30, 2004).

Nothing has changed as a matter of law since EPA offered that analysis of its legal authority to regulate EGUs. The D.C. Circuit's later vacatur of EPA's removal of EGUs from the list of § 112(c) source categories in *State of New Jersey v. EPA*, 517 F.3d 574 (2008), avoided addressing legal arguments about the legality and scope of EPA's December 2000 regulatory determination. EPA has offered no explanation or legal analysis for its abrupt shift in its interpretation of its legal authority to regulate HAP emissions from EGUs under § 112(d).[10] EPA's 2004 legal analysis remains the correct one -- EPA only has authority to regulate mercury emissions from coal-fired EGUs.[11]

2. **The SBREFA SER failed to correctly address Setting MACT floors**

In recent § 112(d) MACT rulemakings, EPA has set MACT limits using a pollutant-by-pollutant approach. Under this approach, EPA identifies the lowest emitting units to determine the MACT floor for a given HAP. EPA then directs its attention to the next HAP, ignoring those units it just determined were the "best performing" in setting the MACT floor for the first HAP, and establishes the next MACT floor based on a different set of units. EPA repeats this process until MACT floors have been set for all HAPs. The end result is a set of MACT floors that do not represent the emission controls achieved by an *actual*, best-performing unit. Instead, they reflect the performance of a hypothetical, ideal unit that does not exist in the real world.

Section 112(d)(3) of the CAA expressly requires that emissions limitation for new units should not be less stringent "than the emissions control that is achieved in practice by the *best controlled similar source*." For existing units, the emission standards "shall not be less stringent, and may be more stringent, than the average emissions limitation achieved by the best performing 12 percent of *sources*." CAA § 112(d)(3)(A) (emphasis added). Section 112(a) defines major and area sources as any "stationary source located within a contiguous area and under common control." That section also defines the term "stationary source" as having the same meaning as that term has under CAA § 111(a). That subsection of the CAA defines a

[10] This is another example of why this small business panel process is so deficient. The Agency has drastically shifted its legal analysis of § 112 with huge resultant regulatory implications without any explanation. Small entities are left to try to divine EPA's logic.

[11] Of course, EPA's legal authority to regulate mercury emissions hinges on the factual adequacy of its December 2000 regulatory determination. In 2004, EPA admitted that its December 2000 finding was factually in error. As the rulemaking record now stands, that conclusion remains valid.

"stationary source" as "any building, structure, facility, or installation which emits or may emit any air pollutant." CAA § 111(a)(3).

These statutory provisions reveal a clear congressional intent that MACT floors must be based on the actual performance of an actual source or sources. These statutory provisions do not allow MACT floors to be set on the basis of a hypothetical, ideal units nor do they allow the "emissions control" achieved by the best sources to be determined using a pollutant-by-pollutant approach on a changing group of best performing units.

As a factual matter, EPA's pollutant-by-pollutant approach makes no sense when applied to EGUs. By focusing on one HAP at a time, EPA misses the antagonistic effects of given HAP limit will have on other regulated emissions. For example, the production of Carbon Monoxide (CO) during the combustion process in an EGU boiler is inversely related to NO_x production. If EPA were to set a surrogate CO limit for organic emissions, plants could not meet that limit if they were also required to minimize its NO_x emissions.

3. **Although the SBREFA SER panel did discuss Subcategorization, the discussions of Subcategorization were inadequate and overly brief.**

For a source category as broad and diverse as coal- and oil-fired power plants, EPA must establish subcategories before setting MACT limits. Section 112(d)(1) allows EPA to distinguish among "classes, types and sizes of sources" in setting MACT limits. In the presentation material, EPA explains that it will evaluate a number of possible subcategorization approaches including boiler design, coal rank, unit type, oil type, and duty cycle. All of these factors are reasonable bases for subcategorization. **EPA should add the size of an EGU to the list of subcategorization approaches it considers when proposing the MACT rule.** Beyond this general observation, APPA cannot provide more specific comments because of the lack of any analyses of the ICR data. However, APPA hopes to identify additional subcategorization concepts during a more detailed and effective SBREFA panel and during the official comment period after the proposed rule has been published.

Closely related to the issue of subcategorization is the question of whether EPA should set separate § 112 limits for EGUs that are area sources. *APPA discusses below why EPA should set area source limits for EGUs.*

4. **Variability of pollutants:**

The emissions of hazardous air pollutants are highly variable from a given EGU, even the best performing ones. The D.C. Circuit in *National Lime Ass'n v. EPA* held that where a statute requires a standard to be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur." 627 F.2d 416, 431 n.46 (D.C. Cir. 1980). The court expanded on this holding in *Sierra Club v. EPA*, 167 F.3d 658, 665 (D.C. Cir. 1999), when it stated that "[i]t is reasonable to suppose that if an emission standard is as stringent as 'the emissions control that is achieved in practice' by a particular unit, then that particular unit will not violate the standard." In order to assure that an emission limit is set at a level the best performing source(s) will not violate, EPA must assess the variability in emissions of that unit. *See Mossville Environmental Action Now v. EPA*, 370 F.3d 1232, 1242 (D.C. Cir. 2004) (EPA's standard was reasonable because EPA recognized the large variability in emissions and supported its standard with record data). In *Sierra Club v. EPA*, 255 F.3d 855, 864-65 (D.C. Cir. 2001), the court instructed EPA to consider the efficiency of control equipment but also non-technology factors that may influence the emissions of the best performing units.

EPA's ICR required EGUs to conduct stack sampling over a three-day period. That snapshot of a unit's HAP emissions is not indicative or representative of the unit's emissions over longer periods of time. EPA must account for emissions variability in order to determine the level of performance achieved by the best performing units. EPA's presentation materials note the need to assess variability and identify three sources of variability that can affect a unit's HAP emissions: (1) fuel variability (both in the coal from a single mine as well as variability at plants that burn coals from multiple sources); (2) performance variability; and (3) load variability. The critical question is how EPA plans to modify the stack emissions reported during the ICR to account for all these sources of variability. <u>The presentation material provided by the EPA does not provide a detailed answer to this question</u>. It simply notes that EPA used an upper predictive level ("UPL") of 99% in other MACT rulemakings without explaining how it would apply a UPL to the specific facts of the EGU MACT rule. **APPA cannot provide meaningful comments on EPA's variability adjustments without more detailed information from EPA**. What remains essential is that EPA properly and fully account for variability in setting MACT limits when proposing any rule.

5. **Treatment of non-detects**

Many HAP measurements made during the EGU ICR were at or below method detection and method quantitation limits. In addition, detection limit information was inconsistently reported by ICR test contractors. How EPA uses these very low measurements will have significant impacts on the MACT floors EPA calculates as well as later compliance demonstrations. **EPA's presentation material fails to explain how EPA will address measurements at or below a methods detection limit and quantitation limit.**

A large percentage of the dioxin/furan and non-dioxin organics measurements from ICR testing were at or below the method detection limit. For those two HAP categories, EPA should establish work practice standards instead of setting MACT limits. Section 112(h) of the CAA allows EPA to set work practice standards where it is not feasible to prescribe or enforce an emission standard. It is not feasible to enforce an emission limit when the uncertainty about the accuracy of a compliance measurement is as great as the measurement being report. This is the case when actual emissions are near the method detection limit. A work practice standard is the best way to avoid compliance issues where actual emissions at or below the detection and quantitation limits of a method.

6. **The use of alternative health based limits under § 112(d)(4)**

Section 112(d)(4) is designed to prevent the promulgation of unduly stringent emission limits simply for the sake of regulation. Section 112(d)(4) allows EPA to set health-based limits for certain HAPs based on established health thresholds as an alternative to promulgating technology based limits under § 112(d)(3). Section 112(d)(4) applies to non-carcinogenic HAPs[12] for which EPA has established a health threshold such as a reference concentration (RfC) or a reference dose (RfD). EPA defines a reference concentration in its IRIS database as "[a]n estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime."[13] Thus, human exposures to

[12] Almost without exception, EPA assumes a linear, no-threshold dose-effect relationship for carcinogens.

[13] The definition for a reference dose is essentially the same except it focuses exposure by pathways other than inhalation.

a HAP at levels below its RfC are considered "safe", particularly given the uncertainty factors that EPA uses in its derivation of a RfC.

Section § 112(d)(4)'s inclusion in the 1990 CAA Amendments indicates a congressional intent to retain the health endpoint of the original § 112 -- protection of public health with an ample margin of safety.[14] If the emissions of a given HAP from all sources in a source category are at a level where public health is protected with an ample margin of safety, then there is no practical need for or benefit from further regulation. **APPA strongly urges that EPA should set health-base standards under § 112(d)(4) when facts support its use, such as for acid gas emissions from coal-fired EGUs.**

7. **Monitoring**

A number of SBREFA provisions recognize the significant impacts monitoring and recordkeeping requirements can have on small entities. Federal agencies are encouraged to find ways to lessen the impact of monitoring and recordkeeping requirements on those entities. Small entities do not possess the monetary resources, manpower, or technical expertise needed to operate cutting-edge monitoring techniques such as mercury and Particulate Matter or PM CEMs. EPA should develop more limited monitoring requirements for small EGUs. Unfortunately, EPA's presentation materials do not discuss any monitoring alternatives so more detailed comments are not possible. This was a prime example of a failure by the EPA staff to identify monitoring alternatives that could have been offered during the SER panel.

EPA Should Establish Area Source Standards

Section 112 of the CAA allows EPA to set area source standards for those stationary sources that do not emit or have the potential to emit more than 10 tons/yr of any individual HAP and 25 tons/yr of all HAPs.[15] If EPA decides to set an area source standard, it must use "generally available control technologies or management practices by such sources to reduce

[14] The ample margin of safety concept also underlies the current residual risk provisions of CAA § 112(f).

[15] A "major source" is defined in CAA § 112(a)(1) as a stationary source that emits HAPs above the 10 tons/yr and 25 ton/yr thresholds. An "area source" is defined in CAA § 112(a)(2) as any stationary source that is not a major source.

emissions of hazardous air pollutants."[16] Congress included an area source option in § 112(d) as recognition that the risks posed by HAP emissions from area sources were far smaller than the ones posed by major sources and that less stringent rulemaking standards were appropriate. Many EGUs owned by small public power entities are area sources. Some of these units are small (*e.g.* less than 100 MWs) and thus have relatively low HAP emissions. Others employ combustion processes (*e.g.* fluidized bed technology) or have installed control equipment (*e.g.* scrubbers) that reduce HAP emissions to levels that qualify them as area sources**. One of the most positive moments of the SER SBREFA panel meeting on December 2, 2010 was the point where we discussed the option of using area source standards. APPA strongly encourages the EPA to use area source standards for controlling mercury from smaller coal fired power plants**.

EPA should exercise its discretion, as it has done in other § 112 rulemakings,[17] and set separate area source standards for coal- and oil-fired EGUs.[18] Area source rules would lessen the regulatory burdens of a § 112 EGU rule on many small entities.

Small Entities Face Significant Compliance Problems with Any EGU MACT Rule

CAA § 112(i)(3)(A) requires existing sources to comply with a MACT rule no later than three years after the effective date of the MACT rule. Other provisions of § 112(i) provide possible extensions of the compliance date: one year by the EPA Administrator (or a State if it has implementation authority),[19] and an additional two years by a Presidential exemption.[20] While the entire utility industry will face great challenges to comply with a MACT standard

[16] CAA § 112(d)(5).

[17] For example, EPA recently proposed area sources standards for certain industrial boilers.

[18] On Slide 7 of EPA's presentation material, the Agency notes that "[t]he section 112 definition of EGUs does not distinguish between area and major sources." One could interpret this bullet as suggesting that EPA believes it lacks legal authority to set area sources limits for EGUs. The definition of an "electric utility steam generating unit" in CAA § 112(a)(8) does not limit EPA's legal authority to set area source limits for those facilities. The most obvious reason an EGU definition was included in § 112(a) was because one was needed to identify which units were subject to the unique provisions of CAA § 112(n)(1)(A). Furthermore, Congress had already included generic definitions of "major" and "area" sources in § 112(a) so there was no need to include those terms in the later definition of an "electric utility steam generating unit."

[19] CAA § 112(i)(3)(B)

[20] CAA § 112(i)(4). The Presidential exemption can be granted more than once.

within three years, small municipal EGUs will face far greater problems. It is highly unlikely those units will be able to meet a three-year deadline and EPA should extend the compliance deadline for those units as part of any final MACT rule.

Municipal utilities that qualify as small entities typically often own only one or two EGUs. If stringent emission limits are imposed by an EGU MACT rule, utilities across the country will scramble to secure the equipment, contractors and skilled craftsmen needed to install new control equipment. Large utilities have leverage to get their plants retrofitted first. Small municipal utilities will find themselves at the end of a long line, making it highly unlikely that new control equipment can be installed within three years.

Small municipal utilities face additional daunting problems in complying with a MACT rule. The financing of new control equipment will be largely borne by the community served by the municipal utility. APPA members that qualify as small entities serve smaller communities that do not have large sums of money on hand to pay for extensive plant additions. Most municipals will need to seek external funding before beginning any design or construction activities.

Some municipal power plants are also located very close to the population they serve. Those plants face space constraints that will prevent them from installing additional control equipment.

For all these reasons, EPA should provide small entities additional time to comply with the EGU MACT rule.

Conclusion

While APPA appreciates being invited to attend the December 2, 2010 SBREFA SER panel meeting as an observer or viewer, we believe that this process was inadequate, hastily convened, lacking in any serious regulatory alternatives to be offered for discussion, and lacking in any sincere effort to identify ways to reduce the costs and burdens of the largest single regulation in the utility sector. APPA also believes that the EPA has given only cursory thought to the reliability impacts to all of the various EPA regulations hitting the utility sector from 2013-2020 that are best identified on the diagram on page 3. **APPA believes that the SER panelists should be re-convened (by phone or in person) after the EPA has more thoroughly evaluated the sampling data and outlined several technical options and regulatory**

alternatives. These regulatory alternatives should include subcategorization and GACT controls and area source controls amongst other options. Any regulatory options to reduce the cost to the many electric utility small party entities under SBREFA will also benefit the hundreds of thousands of commercial customers that are also SBREFA qualified commercial and industrial customers of electricity provided by public power**.**

Thank you. For further contact at APPA:

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APPENDIX K

Why New CO_2 Regulations Could Produce Windfall Profits and Unproductive Costs for Consumers

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ISSUE BRIEF

Why New CO_2 Regulations Could Produce Windfall Profits and Unproductive Costs for Consumers

Overview

This issue brief describes how the layering of a problematic wholesale market structure on top of the implementation of EPA's New Source Performance Standards (NSPS) for carbon dioxide (CO_2) will produce excess costs for consumers and windfall profits for owners of merchant electric generation units. These "unproductive costs" represent a diversion of funds that would be better spent on environmental improvements or on reducing costs to already overburdened consumers.

These profits are in fact a central driver in the position taken by owners of power plants for a more stringent NSPS that attended the EPA listening session on February 4, 2011. Those voicing support for stricter NSPS standards for CO_2 largely overlap with those entities identified by financial analysts as beneficiaries of greater EPA regulation.[1] The reason that a handful of large power plant owners will boost their already lucrative earnings as an outcome of these regulations is the highly problematic wholesale electricity market structure in many parts of the country.

In these parts of the country, including the mid-Atlantic, Northeast, Midwest, California and Texas, wholesale electricity markets are operated by large bureaucratic entities, known as Regional Transmission Organizations (RTOs). While the markets operated by RTOs are highly complex, their central features have allowed owners of unregulated generation – known as "merchant power plants" – to earn excessive profits. For a more detailed description of these markets, see *A Primer on Electricity Markets* at the end of this Issue Brief. The remainder of this

[1] These companies include Exelon, FirstEnergy, Dominion Power, and Constellation.

document explains how the pending EPA regulations will exacerbate these windfall profits and costs to consumers.

What companies are the likely recipients of these windfall profits?

Owners of large nuclear power plants located within RTO regions will be the largest beneficiaries – and these extra earnings will result from no changes in their operations or additional investments. An analysis by Credit Suisse projects that the market value of Allegheny, Exelon, and FirstEnergy would all increase between 20 and 25 percent, and their earnings would increase by almost 40 percent by 2015 under a 60 gigawatt[2] (GW) coal plant retirement scenario.[3] An analysis by FBR Capital found that the tightening of power supply resulting from the retirement of 45 GW of coal capacity would greatly increase the earnings of FirstEnergy and PPL.[4]

These earnings potentials are the reason behind the merchant power plant owners' simultaneous support for stricter environmental regulations, alongside inadequate consumer safeguards in the RTO-operated wholesale electricity markets. As the Wall Street Journal noted:

> Eight leading utility CEOs responded recently to one of our editorials with a letter defending the EPA, claiming that the coal retirements are "long overdue" and that the regulations will "yield important economic benefits." *What they didn't mention is that those benefits will mostly accrue to the businesses they happen to head*.[5] (Emphasis added)

What are the primary EPA regulations that will impact the costs of electricity?

In addition to an NSPS for CO_2, the major EPA regulations affecting the utility industry that have been the subject of recent studies projecting future coal plant closures are:

- Cooling Water Intake Structures, Section 316(b) of the Clean Water Act
- Maximum Achievable Control Technology Standards for Hazardous Air Pollutants
- Regional Transport Rule
- Coal Combustion Residuals (CCR) Disposal Rule

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[2] One gigawatt is equal to 1,000 megawatts or one million watts. There are about 300 GW of coal capacity in the United States (US Energy Information Administration, http://www.eia.gov/emeu/aer/pdf/pages/sec8_42.pdf)

[3] *Growth From Subtraction: Impact of EPA Rules on Power Markets*, Credit Suisse Equity Research, September 23, 2010, http://op.bna.com/env.nsf/id/jstn-8actja/$File/suisse.pdf, Exhibit 106, p. 53 and Exhibit 111, 55

[4] *EPA regs may shut 70,000 MW of U.S. coal plants: FBR*, Reuters, December 13, 2010, http://www.reuters.com/article/2010/12/13/us-utilities-epa-coal-idUSTRE6BC3JN20101213

[5] *The EPA's Utility Men; Anticarbon regulations and the corporate rent-seekers who love them*, The Wall Street Journal, December 23, 2010, http://online.wsj.com/article/SB10001424052748704694004576019730082447432.html

How will these new Clean Air Act regulations impact the supply of power?

A number of recent studies analyze the likelihood that owners of coal plants will make the decision to shut down a facility rather than incur the costs of retrofitting to comply with EPA regulations currently under development.[6] Most of these studies found the reduction in coal plant capacity to be significant, equal to about 20 percent of all coal capacity, as summarized in the following table. **These projections do not include the proposal of NSPS standards for CO_2.**

2010 Special Reliability Scenario Assessment, North American Electric Reliability Corporation, October, 2010, Table IV-6, http://www.nerc.com/files/EPA_Scenario_Final.pdf	10-35 GW of coal, and 40-70 GW of all generation by 2018
Growth From Subtraction: Impact of EPA Rules on Power Markets, Credit Suisse Equity Research, September 23, 2010, http://op.bna.com/env.nsf/id/jstn-8actja/$File/suisse.pdf	60 GW of coal capacity between 2013 and 2017
Potential Coal Plant Retirements Under Emerging Environmental Regulations, The Brattle Group, December 8, 2010, http://www.brattle.com/_documents/UploadLibrary/Upload898.pdf	50–66 GW of coal by 2020
FBR Capital, *EPA regs may shut 70,000 MW of U.S. coal plants: FBR*, Reuters, December 13, 2010, http://www.reuters.com/article/2010/12/13/us-utilities-epa-coal-idUSTRE6BC3JN20101213	45 GW likely, with a range of 30 to 70 GW, over the next several years

How will these coal plant closures produced by the new Clean Air Act regulations increase electricity costs paid by consumers and excess profits of merchant generators?

The costs to consumers from these coal plant closures and retrofits will fall into two categories: direct and indirect (or unproductive) costs. *Direct costs* cover the construction of new cleaner plants to replace the mothballed coal plants and retrofitting those plants that remain in operation. *Indirect costs* are the increase in energy and capacity market prices resulting from the constrained supply of power, and increases in the price of natural gas resulting from the increased demand for this fuel. As explained later, increases in natural gas costs within RTO – operated markets will be paid for all energy produced, regardless of the source, and are therefore subject to a significant multiplier effect in these markets. These indirect costs are not direct expenditures on actions that will improve the environment, and instead are "unproductive costs" that will simply burden consumers.

But aren't natural gas costs expected to remain low?

Despite the conventional wisdom that natural gas prices are likely to remain low, there are several reasons why this is unlikely. First, a number of the closed coal plants will inevitably need to be replaced with natural-gas or renewable energy sources. Second, because wind and solar

[6] These analyses look at the impact from regulations listed above for cooling water intake structures, Maximum Available Control Technology, Regional Transport Rule, and coal-ash disposal.

power are variable sources of energy and cannot be called upon to deliver power at the exact moment when needed, a significant amount of backup power will be required to integrate these renewable sources, and will most likely come from natural gas facilities.[7] These two developments, will likely drive up the demand for natural gas significantly. The potential for shale gas supplies to maintain natural gas prices at current low levels in the face of increased demand is highly unlikely given the uncertainty about the technologically achievable quantities and environmental costs of shale gas extraction.[8]

How does the market structure affect the amount of these unproductive costs?

For generation owned by a vertically-integrated regulated utility, the decision to retrofit or close a coal plant would be based on an assessment of the costs of replacing that power source as compared to retrofitting the plant. Because the utility is under the obligation to provide a reliable supply of power to their customers, if it were to close the coal plant, it would need to invest in new generation (either through construction or contracts) and energy efficiency to make up for the reduction in supply. Following a review and approval of such expenses by the relevant regulatory bodies, the direct costs would be passed on to customers through rates. Any increases in the cost of natural gas would be passed on to consumers through the fuel adjustment clause, but only for the energy actually generated by those plants.

For merchant power plants in regional transmission organization (RTO)-operated markets, the indirect or unproductive costs would be greatly exacerbated. Owners of these plants would decide to retrofit a coal plant only if they expect their future market earnings will exceed such expenses, with no consideration of the impact on reliability. Merchant power plants sell power into RTO-operated energy markets using the single-clearing price model, where the plant with the highest offer to sell power required to meet demand sets the price for all power used in each hour. Plants with the highest operating costs, largely determined by the price of fuel, are generally the marginal plants. Nuclear power plants, which have the lowest operating costs, are almost never the marginal plant, and sell their power at prices that exceed their operating costs in all hours. Some RTOs also operate capacity markets that provide large sums of revenue to cover the generators' fixed costs for keeping plants ready to provide power. Capacity markets also use a single-clearing price model, and greatly benefit older, largely depreciated plants that have paid off the bulk of their fixed costs – including many nuclear plants.

Unlike generation owned by a vertically-integrated utility, the future earnings of merchant generation owners would be higher for their remaining existing plants if a portion of generation is shut down and the supply of power becomes constrained. One likely scenario is for merchant

[7] The Department of Energy's 20% Wind Scenario projects an additional 70 GW of natural gas-fired combustion turbine capacity. See 20% Wind Energy by 2030 Report, Appendix A, Figure A-6, p.153, http://www.20percentwind.org/report/Appendix_A_20PercentWindScenarioImpacts.pdf

[8] For a discussion on the uncertainties surrounding future shale gas production, *see Implications of Greater Reliance on Natural Gas for Electricity Generation*, Prepared by Aspen Environmental Group for APPA, July 2010, p. 28-38, https://appanet.cms-plus.com/files/PDFs/ImplicationsOfGreaterRelianceOnNGforElectricityGeneration.pdf.

generators to strategically close the plants that are the most costly to retrofit while allowing the remaining plants, especially nuclear and lower emission coal plants, to benefit from the resulting higher prices.[9] Several recent analyses have found that the closure of coal plants is in fact likely to be greater for merchant units. The Brattle Group found that most of the coal plants likely to retire will be merchant units, accounting for 64 to 76 percent of merchant coal capacity compared to 1 to 4 percent of regulated coal, who would be much more likely to retrofit the plants. [10]

Credit Suisse projects that the likely supply constraints resulting from the coal plant closures would increase power prices by $5 to $10 per mwh – equal to a 10 to 20 percent increase from the 2010 average energy prices for PJM.[11] This same analysis predicts a dramatic increase in the capacity price in the non-transmission constrained region of the RTO, from $27 to $100 per MW/day.

As the supply becomes more constrained, less efficient and higher operating cost plants will set the clearing price.[12] In addition to the impact of supply constraints, natural gas costs will significantly influence the electricity prices in RTO markets. Because the RTO markets use a single-clearing price model, any price increases for the highest-cost units that set the clearing price are multiplied by all the electricity used in that time period. For example, in the PJM Interconnection, the largest RTO, covering the Mid-Atlantic States, natural gas accounts for just one-tenth of the electricity generation but typically sets the clearing price in one-fourth of the hours.[13] Because the hours when a natural gas-fired plant is the clearing unit are during "peak"

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[9] For example, Credit Suisse notes that "the retrofit / closure decision will not occur in a vacuum such that plants 'on the bubble' for investment could be attractively economic as other plants are pulled from the market." *Growth From Subtraction: Impact of EPA Rules on Power Markets*, Credit Suisse Equity Research, September 23, 2010, http://op.bna.com/env.nsf/id/jstn-8actja/$File/suisse.pdf, p. 36. Similarly, Fitch Ratings concluded that: "Merchant generation that does not rely on coal (or coal-fired generation that is already highly controlled) could increase its profitability if a significant portion of coal-fired generation in the same region is retired and heat rates rise in the region due to stringent enforcement of new EPA rules." *Time to Retire? US Coal Plants in Environmental Crosshairs*, FitchRatings, February 2011, p. 2 http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=604365

[10] *Potential Coal Plant Retirements Under Emerging Environmental Regulations*, The Brattle Group, December 8, 2010, p. 6 http://www.brattle.com/_documents/UploadLibrary/Upload898.pdf,

[11] The load-weighted real-time and day-ahead locational marginal prices for 2010 were $48.35 and $47.65 per megawatt-hour, respectively. *2010 State of the Market Report for PJM*, Section 2, p. 24-25, Monitoring Analytics, March 10, 2011, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010/2010-som-pjm-volume2-sec2.pdf

[12] FitchRatings, for example, notes that "the retirement of a large number of coal-fired power plants in a region could result in less efficient gas-fired power plants becoming the marginal dispatch units." FitchRatings, February 2011, p. 7.

[13] *2010 State of the Market Report for PJM*, Section 2, Table 2-14, p.47 and Section 3, Table 3-43, p.204, Monitoring Analytics, March 10, 2011, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010.shtml

periods of higher electricity use, these hours can account for a much greater amount of energy consumption. The closure of coal plants combined with an increase in natural gas costs will mean that both the number of hours when natural gas-fired units clear the market and the price in those hours will rise significantly. The result will be greater revenues for all existing power plants with lower operating costs than the marginal natural gas plants – especially the nuclear power plants that have been largely paid off by ratepayers while regulated.

This assessment of the potential profit increases is confirmed by a number of recent statements by large merchant generation owners regarding new EPA rules. A few examples are:

- As reported by The Wall Street Journal, John Rowe, the CEO of Exelon, the owner of a large fleet of nuclear power plants stated on a conference call with financial analysts last summer that pending EPA rules "increase operating costs for the coal-fired generators…and ultimately increase the clearing price for energy." Mr. Rowe also stated that "the upside to Exelon is unmistakable" and that every $5 increase per megawatt-hour translates into $700 million to $800 million in new annual revenue.[14]
- Constellation Energy is looking to the capacity markets to generate additional revenue, and projects such revenue to increase by $60 million between 2011 and 2014.[15]
- PPL Corporation lists pending coal plant closures as one of the "catalysts for growth" in its earnings in a February 2011 presentation to financial analysts, stating that the "[p]roposed EPA regulations are expected to be a net benefit given our mix of generation."[16]

One of the greatest beneficiaries of the coal plant closures in RTO-operated markets will be the owners of merchant nuclear power plants, who will see dramatic increases in earnings – for doing absolutely nothing. Those coal plants that can comply with EPA regulations at minimal costs will likely see increases in their earnings as well, for little or no changes in their operations. As a result, consumers will pay higher costs even where no money is spent on the development of cleaner energy supply or energy efficiency measures, making these costs truly unproductive.

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[14] From statements made during Exelon's second-quarter earnings call in July 2010, quoted in *The EPA's Utility Men - Anticarbon regulations and the corporate rent-seekers who love them*, the Wall Street Journal, December 23, 2010.

[15] Constellation Energy, 2010 Year-End Earnings Presentation, February 4, 2011, Slide 12, http://files.shareholder.com/downloads/CEG/1147753753x0x439125/6a8484c5-8fd6-4f4d-b0df-cd19a99f6d36/2010%20Year-End%20Earnings%20Presentation%20-%20SUPPORTING%20MATERIALS.pdf

[16] PPL Corporation, Credit Suisse Global Energy Summit, February 8-11, 2011, Slide 12, http://files.shareholder.com/downloads/PPL/1184323975x0x439853/e3b801ef-3a55-42c8-9c6f-52bce977d833/PPL_IP_2.8.11.pdf

A Primer on Electricity Markets

How are electricity markets regulated?

There are two types of electricity markets; retail and wholesale. Retail sales cover the purchase of electricity by homeowners, businesses, and factories from the local utility, which is one of three types:

> Investor-owned utilities (often called "IOUs") are for-profit companies owned by shareholders and regulated by state commissions;
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> Public power utilities are not-for-profit electric utilities that are owned and operated by states or political subdivisions of a state (cities, public utility districts, and utility boards), and are typically regulated either by an elected or appointed governing board or a city council.
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> Rural electric cooperatives are private not-for-profit entities owned by the customers they serve, and are usually governed by a board of directors, elected by the members of the cooperative, although they are also subject to state commission oversight in some states.

All of these retail utilities obtain power from two sources; electricity generating plants that they own, or purchases of power from other utilities or independent owners of generating plants. The second source, power purchased from other sources, is as a wholesale purchase. Wholesale markets are regulated by the Federal Energy Regulatory Commission (FERC). The local utility's rates are based on a formula that reflects their costs of producing, purchasing and distributing power, and for the IOU's, a return to shareholders. Wholesale electricity costs therefore impact the customers' bills in proportion to the amount of power that the utility does not generate on its own and must purchase from other generators.

What is meant by the restructuring of electricity markets?

The terms restructuring refers to a series of changes implemented in both the retail and wholesale electricity markets over the past 20 years intended to introduce greater competition into these markets – a goal that has not been obtained.[17]

On the retail level, a number of states, including California, New York, Illinois, Maryland, New Jersey, Pennsylvania and several New England states, implemented "retail choice" in the 1990s. Individual households, businesses and factories were all given the right to purchase power from non-utility providers. (In most states that implemented retail choice, public power utilities were allowed to "opt out", and almost all of them did so.) As a common component of retail choice, the IOUs were required to sell their generating plants and to purchase power from the wholesale markets. The result was that a large pool of merchant power plants now sells power at unregulated prices and no longer has an obligation to serve customers. Moreover, the impact of

[17] For more information and detailed studies of the restructured wholesale electricity market, see APPA's Electric Market Reform Initiative, at www.publicpower.org/emri.cfm.

the wholesale markets was expanded – customers of these restructured IOUs now pay retail rates that are a reflection of the wholesale power markets rather than the costs of their utilities generation. Most public power utilities also rely on purchases from the wholesale markets for the energy they supply to their customers, and many rely almost exclusively on such purchases.

Meanwhile, the wholesale markets underwent a problematic restructuring during this time period. FERC formerly required the prices for the sale of wholesale power to be determined by the cost of producing that power. But since the early 1990s, FERC has increasingly relied on highly elusive "competition" in wholesale power markets to set prices, and has granted "market-based rate authority" to many sellers of wholesale electric power, subject only to reporting and limited oversight requirements. This allows electric generators to sell power at market prices, which frequently exceed the actual costs of generating the power.

FERC also encouraged the creation of entities called regional transmission organizations (RTOs). One function of these RTOs is the operation of wholesale markets, featuring short-term spot energy markets setting hourly rates in "single-clearing price auctions." All generators whose electricity is purchased in a given hour receive the highest price bid to supply electricity in that hour. Many RTOs have also created complex "capacity markets" that also operate on single-clearing price basis, and provide large sums of revenue to generators simply for keeping plants ready to provide power if needed, or to customers who agree to cut back their power when supplies are short.

The RTOs cover the mid-Atlantic, New England, New York, California, the Midwest and Texas. Almost all of the states that have implemented retail access and are located within these RTOs.

These changes in the wholesale and retail markets were predicated on assertions by federal and state officials and other RTO proponents that they would promote competition, spur efficiencies and innovation, and lower rates for consumers—assertions that, for the most part, have not come to fruition. In fact, the greatest beneficiaries have been the merchant power plant owners, especially the owners of older power plants (many of them nuclear) that have been largely depreciated. These owners have earned profits that greatly exceed what they had previously earned under regulation – profits that are funded by higher prices for consumers in retail access states located in RTO markets.