August 4, 2011

VIA E-DOCKET

U.S. Environmental Protection Agency
Docket Center
1200 Pennsylvania Ave. NW, Mail Code 2822T
Washington, DC 20460

Re: EPA-HQ- OAR–2009–0234; EPA-HQ- OAR–2011–0044
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
76 Fed. Reg. 24976 (May 3, 2011)

Dear Sir or Madam:

The Council of Industrial Boiler Owners (CIBO) appreciates the opportunity to comment on EPA's proposed MACT and NSPS rules for Coal and Oil-Fired Electric Utility Steam Generating Units.

CIBO is a broad-based association of industrial boiler owners, architect-engineers, related equipment manufacturers, and University affiliates with over 100 members representing 20 major industrial sectors. CIBO members have facilities in every region of the country and a representative distribution of almost every type of boiler and fuel combination currently in operation. CIBO was formed in 1978 to promote the exchange of information within the industry and between industry and government relating to energy and environmental equipment, technology, operations, policies, law and regulations affecting industrial boilers. Since its formation, CIBO has been active in the development of technically sound, reasonable, cost-effective energy and environmental regulations for industrial boilers. CIBO supports regulatory programs that provide industry with enough flexibility to modernize – effectively and without penalty – the nation's aging energy infrastructure, as modernization is the key to cost-effective environmental protection.

BACKGROUND

During calendar years 2010 - 2011, EPA has proposed the most costly Clean Air Act regulations in history, which will directly or indirectly affect all energy consumers across the nation, and in particular, industrial consumers of energy. Many CIBO members will be directly regulated by the utility MACT and NSPS rules. Many other CIBO members will also be indirectly affected by these rules, which will impose on utility sources unprecedentedly high compliance costs, which will be passed through to industrial energy users in the form of higher electricity costs. CIBO members will also be affected by how EPA administers and interprets the MACT provisions of the Clean Air Act, which govern all listed subcategories of sources, including industrial, commercial and institutional boilers owned and operated by CIBO members.

GENERAL COMMENTS

I. The utility MACT rule will adversely affect the cost-effective operation of industrial energy operations.

The utility MACT is one of a number of major regulations, which combined will impose never-before-seen compliance costs on electric energy production. The cumulative impact of these rules on the utility sector has been well documented. In recent testimony before Congress, the US Chamber of Commerce provided testimony highlighting the impact on electricity production of EPA regulations:

> American Electric Power Co. made headlines last month when it disclosed that EPA's "train wreck: of coal regulations – Coal Ash, Utility MACT, the Transport Rule and Cooling Water Intake Structures – would force the utility to retire 6,000 megawatts of coal-fired generating capacity and spend another $6 billion to $8 billion reworking the rest of its fleet. AEP would close three power plants in West Virginia, one in Ohio and one in Virginia, and would retire several boilers at coal plants in Indiana, Kentucky, Ohio, Texas and Virginia.
>
> AEP is not alone. Six other power plants have announced early retirement due to excessive regulation: Portland Gas & Electric's Boardman coal-fired power plant in Oregon; Exelon Corporation's Oyster Creek Nuclear Generating Station in New Jersey; TransAlta Corporation's Centralia coal-fired power plant in Washington; and, just this week, three Georgia Power plants in the next two years. In each case, the utility was forced to choose between installing several hundred million dollars' worth

of pollution controls to comply with EPA regulations, or simply shut down early. In all cases, the utility chose early retirement.[1]

Reducing electricity supply through utility plant shutdowns, making it more expensive through regulations that discourage cost-effective coal-fired generation or that impose other high-cost mandates, directly affects the industrial sector, which is the largest end-user of energy. By comparison with their overseas competitors, "the US industrial sector consumes more energy than the industrial sector of any other OECD country…" *EIA Industrial Energy Outlook 2010.* Increasing the cost of energy to industrial sources reduces their ability to compete in the marketplace. It reduces the ability of industrial, commercial and institutional sources to expand capacity in the US, create jobs and increase their contribution to the GDP.

The 2010 EIA outlook shows the full extent of the current economic challenges faced by the US industrial sector in this economy: "A 9.1-percent decline in industrial demand for electricity, which fell to the lowest level since 1987, accounted for most of the decline in overall electricity consumption. The drop in industrial electricity demand reflected the 9.3-percent drop in industrial output, as measured by the Federal Reserve Bank's index of industrial production."[3]

This rule is also expected to result in an increase in natural gas prices. As this rule affects coal and liquid fired utility boilers, many utility companies will transition to natural gas firing instead of installing costly air pollution control equipment. Our members also use natural gas as fuel in some of their industrial boilers and manufacturing processes, but on a smaller scale than that needed to run electricity generation facilities. The National Economic Research Associates (NERA) estimates that natural gas prices will increase by approximately 17 percent in 2016 (much higher than the 1.3 percent stated on page 252 of the Regulatory Impact Analysis for this rule). [2]

Energy availability at globally competitive prices is critical for US industry to be able to survive and invest in future growth. The cost impact analysis of this rule does not reflect the full extent of the impact of this regulation, much less the cumulative impact of the other pending EPA regulations on the electricity sector and all other directly and indirectly affected sectors of the US economy.

[1] Testimony of US Chamber of Commerce before the Committee on Energy and Commerce Subcommittee on Environment and The Economy, U.S. House of Representatives (July 14, 2011).

[2] *See* http://www.americaspower.org/NERA_CATR_MACT_29.pdf for NERA study results.

II. The converging compliance timeframes of the Utility MACT, Boiler MACT, the Cross-State Air Pollution Reduction Rule, and several other EPA Clean Air Act rules will drive up compliance costs for all sources, and places at risk sources' ability to comply within tight deadlines.

EPA has proposed multiple major Clean Air Act rules, all of which require compliance within a limited period of time. As it is, EPA severely underestimates the cost of compliance with its proposed rules. However, in this instance, EPA's cost estimates are even more severely deficient, as they do not account for the effect on cost of high demand on a limited supply of highly specialized contractors that are qualified to design and install the equipment upgrades required by the rules.

It is estimated that over half of coal-fired electric utility capacity will need to install complicated, highly specialized control systems to comply with the Utility MACT rule. Compliance will require regulated sources to contract with, among others, Architect-Engineer (AE) firms, original equipment manufacturers (OEM), fabrication shops, and emissions measurement companies well in advance of the 3-year compliance timeframes EPA has provided for the MACT rules. The supply/demand relationship for these materials and services as well as limited skilled labor pools will drive prices even higher and stretch lead times out further. These limitations will not only impact costs, but also impact grid system reliability due to project time requirements and scheduling limitations for units to be shut down for those modifications.

The unintended but inevitable additional impact on industrial sources is that they will need even more time to comply with the corresponding rules for ICI boilers, due to basic market forces. Utility units are generally much larger than industrial units, and therefore utility contracts for AE, OEM and fabricator work are likely to be given priority over smaller, shorter-term industrial contracts. This will also make it more difficult for industrial sources to obtain contractor guarantees for completion within the compliance timeframe.

EPA's cost estimates for compliance with the Utility MACT do not take into account the market realities that will drive up the cost of equipment upgrades due to EPA's converging timeframes for compliance with other rules. This will impact industrial sources disproportionately, yet those cost impacts are not addressed by EPA's cost estimates in the Boiler MACT or Utility MACT rules.

EPA has also not accounted for the limited availability of contractors qualified to undertake these projects in setting compliance deadlines. EPA should allow for additional time for compliance with the rules within the limitations of the CAA.

III. CIBO supports the dioxin/furan provisions of the rule and statements in the preamble, which reflect CIBO member data and experience with dioxin/furan measurement in industrial sources, and EPA should revise any contrary provisions and statements in the Boiler MACT rule.

CIBO supports the approach taken by EPA in the utility MACT rule for dioxin/furan (D/F). CIBO agrees with the following conclusions regarding the regulation of D/F from coal-fired utility boilers:

> EPA is proposing work practice standards for non-dioxin/furan organic and dioxin/furan organic HAP. The significant majority of measured emissions from EGUs of these HAP were below the detection levels of the EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units. As the majority of measurements are so low, doubt is cast on the true levels of emissions that were measured during the tests. Overall, 1,552 out of 2,334, total test runs for dioxin/furan organic HAP contained data below the detection level for one or more congeners, or 67 percent of the entire data set. In several cases, all of the data for a given run were below the detection level; in few cases were the data for a given run all above the detection level. For the non-dioxin/furan organic HAP, for the individual HAP or constituent, between 57 and 89 percent of the run data were comprised of values below the detection level.

76 Fed. Reg. 25,040. For the following reasons, CIBO supports EPA's conclusions that work practice standards are appropriate for these compounds.

The majority of the D/F data collected for both the Utility MACT and Industrial Boiler MACT rulemakings are at levels below the capability of the analytical and stack test methods to detect emissions of these compounds. Much of the test data are labeled as being below the method detection limit and the remainder of the data are often flagged as being below the level the laboratory feels can be reported with confidence.

It is not appropriate to treat detection level limited data for purposes of establishing regulatory limits in the same manner as detected values because the uncertainty[3] associated with measurements near or below the method detection limits is too high. The test methods were developed over 30 years ago to measure D/F at concentrations then found in some types of waste incinerator exhaust (levels orders of magnitude higher than those found in exhaust from today's boilers).

All source emission measurements have random (precision) errors associated with the sample collection, sample and equipment handling, sample preparation, and sample analysis. These errors define method detection and quantitation limits and uncertainty in a non-arbitrary, scientific manner (as discussed further below). When emission levels are much higher than the magnitude of these errors, there is a high degree of confidence in the measured value obtained from a single or a few test runs. However, as the measured value decreases, the contribution of these errors to the measured value increases, thus decreasing the confidence level in the accuracy of the measured value from a single or a few runs until the point where the measured value cannot be distinguished from the random error ("noise" level). This is the case with the utility boiler D/F data. When this occurs, the measurement cannot be distinguished from zero with high confidence.

The magnitude of D/F measurement errors typically varies with every measurement and is affected by the characteristics of the sample, skills of the sampler and analyst, specific equipment used, techniques and procedures adopted by individual laboratories and other factors even when following the same published test method (in this case, EPA Method 23). Although EPA Method 23 procedures minimize measurement errors at the stack emission levels and applications for which it was intended, measurement errors are not zero and become significant at the extremely low levels in boiler exhaust.

In setting recent MACT standards (e.g., Industrial Boiler MACT), EPA has acknowledged that the emission limit should not be set below the capability of the applicable test method. However, EPA did not use the widely accepted definition of method detection limit, which is based on the capabilities of multiple commercial laboratories to analyze a sample and identify the presence of a chemical above the "noise" level. In its place, EPA coined a new term, representative method detection limit (RDL) to define a measurement method detection limit which is based on the laboratory detection limits

[3] Uncertainty here refers to the statistical expression of measurement error, such as defined in ASME Performance Test Code 19.1, rather than an inference of something that is unknown.

reported for the tests with the lowest emissions. This erroneous methodology results in estimating D/F detection limits that are lower than those regularly achieved by commercial laboratories.

The detection limit of an analytical method is commonly defined as the lowest concentration that can be distinguished from replicate blanks. The quantitation limit of a method is defined as the smallest concentration of the substance which can be measured with an acceptable level of uncertainty. Detection limits and quantitation limits are defined in a scientific, non-arbitrary manner in various widely-published peer-reviewed consensus guidelines[4] and EPA documents. Quantitation limits of test methods have great significance when measuring very low concentrations of pollutants. In practice, reported values below the method's quantitation limit should not be treated as real values.

As demonstrated by the measurement issues noted, quantifying the actual, extremely low or non-existent dioxin emission levels for the Utility MACT floor units is technologically impracticable (as well as economically impracticable, given that the technological problems cannot be overcome by investing reasonable resources into the problem), and thus, it is not feasible to prescribe or enforce an emission standard for D/F emissions for these units. EPA rightly concludes that Clean Air Act Section 112(h)(1) supports establishing a work practice standard for D/F. The required tune-ups and other emissions reductions being required will result in improved combustion and minimize conditions conducive to D/F formation without establishing a numerical emission standard.

These same EPA conclusions regarding utility D/F emissions apply equally to coal-fired industrial boilers. The levels of D/F reported by industrial boilers are very low, similar to utility boilers. Of the 333 test runs included in EPA's emissions test database, 4.50% (15) are BDL (i.e. all congeners reported as ND), 72.67% (242) are classified as DLL (i.e. some of the congeners reported as ND), 21.92% (73) are ADL (i.e. all congeners reported above detection levels). The D/F data submitted by sources in response to EPA's Phase II ICR reveals even further uncertainty in the data than meets the eye on the surface. D/F sampling and analytical methods offer unique challenges.

CIBO member Eastman's data for its Boiler 30 reveals a further understanding of the uncertainty. The laboratory report for the Eastman Kingston boiler, which is not a top performer,

[4] *See, e.g.*, Keith, L.H. *et al*., Principles of Environmental Analysis, *Anal. Chem.*, *55*, 2210-2218 (1983).

shows that every congener in each test run was either reported as ND (non-detect) or reported a value that was flagged with a "J" qualifier. The "J" qualifier indicates the analyte was quantified with a concentration below the reporting limit, defined as below the lowest point on the calibration curve. Some of the congeners were also labeled "EMPC" (i.e estimated maximum possible concentration) indicating that a peak is detected but did not meet all of the method criteria. Both of these "flags" indicates that there is a high degree of uncertainty associated with D/F data at such low levels as found in coal-fired boiler stack gas. This test report also reveals that some D/F congeners were detected in the field blank, indicating background levels of D/F which cast further doubt and uncertainty to the reported analyte concentrations.

ICI Boilers Also Have Adequate Presence of Sulfur to Inhibit D/F Formation. In the preamble to the Utility MACT, EPA explains its understanding of the reasons for low levels of D/F in coal fired boilers exhaust gases:

> Dioxin/furan emissions from coal-fired EGUs are generally considered to be low, presumably because of the insufficient amounts of available chlorine. As a result of previous work conducted on municipal waste combustors (MWC), it has also been proposed that the formation of dioxins and furans in exhaust gases is inhibited by the presence of sulfur. Further, it has been suggested that if the sulfur-to chlorine ratio (S:Cl) in the flue gas is greater than 1.0, then formation of dioxins/furans is inhibited. The vast majority of the coal analyses provided through the 1999 ICR effort indicated S:Cl values greater than 1.0

76 Fed. Reg. 25,023. A review of the ICR for the coal-fired boilers in the Boiler MACT ICR database shows that the sulfur-to-chlorine ratio is far greater than 1:1. This is intuitive as sulfur content ranges from 0.5% to about 6% and chlorine is usually less than 1,000 ppm.

EPA's Reasoning for Applying Numeric D/F limits to Coal-fired ICI boilers is Flawed. EPA makes the following statement in the Utility MACT preamble:

> Overall, the available test methods are technically challenged, to the point of providing results that are questionable for all of the organic HAP. For example, for the 2010 ICR testing, EPA extended the sampling time to 8 hours in an

> attempt to obtain data above the MDL. However, even with this extended sampling time, such data were not obtained making it questionable that any amount of effort, and, thus, expense, would make the tests viable. Based on the difficulties with accurate measurements at the levels of organic HAP encountered from EGUs and the economics associated with units trying to apply measurement methodology to test for compliance with numerical limit, we are proposing a work practice standard under CAA section 112(h). We do not believe that this approach is inconsistent with that taken on other NESHAP where we also had issues with data at or below the MDL (e.g., Portland Cement NESHAP; Boiler NESHAP). In the case of the Boiler NESHAP, the MDL issue was with the organic HAP. For that rulemaking, the required sampling time during conducting of the associated ICR was 4 hours, as opposed to the 8 hours required in the 2010 ICR. Further, a review of the data indicates that the dioxin/furan HAP levels (a component of the organic HAP) were at least 7 times greater, on average, for coal-fired IB units and 3 times greater, on average, for oil-fired IB units than from similar EGUs. We think this difference is significant from a testing feasibility perspective.

76 Fed. Reg. 25,040.

EPA is splitting hairs to say that D/F emissions from ICI coal units are significantly different from EGUs from a testing feasibility perspective. Utilizing data EPA has made available for both regulations (Boiler MACT and Utility MACT), CIBO has compared average and total emission rates of D/F from the two sectors. That comparison is shown below:

ICI Coal Boilers				
	Pulverized Coal	Stoker	Fluidized Bed	Total/Average
Average D/F (ng/dscm)	0.0104	0.005	0.0092	0.00704
Average D/F (lb/mmBtu)	6.35E-12	3.05E-12	5.62E-12	4.30E-12
Number of Boilers	186	339	30	555
Average Size (mmBtu/hr)	373	184	549	267
Average Op Hours per Year	7,325	6,315	7,903	6,739
Total mmBtu/yr	533,592,973	424,042,292	134,116,350	1,091,751,614
Total D/F (g/yr)	1.5	0.6	0.3	2.5
Average D/F (g/yr)	0.0083	0.0017	0.0114	0.0044
EGU Coal Boilers				
Average D/F (lb/mmBtu)	1.89E-13			
Number of Boilers	1061			
Average Size (mmBtu/hr)	3003			
Average Op Hours per Year	6130			
Total mmBtu/yr	19,531,301,790			
Total D/F (g/yr)	1.7			
Average D/F (g/yr)	0.0016			

This table shows the total D/F emissions estimated for the two sectors differs by only about 32% (2.5 grams for ICIs vs. 1.7 grams for EGUs). The average D/F emissions for ICI coal boilers is only 2.8 times higher than for EGUs – not 7 times higher as reported by EPA (no documentation of EPA's comparison has been found to date in the dockets).

Further, these comparisons (both EPA's and CIBO's) are comparing apples and oranges due to the different test run times upon which the comparisons are based. The ICI boiler data set was determined using 4 hour test runs rather than 8 hour test runs as EPA prescribed for the Utility ICR testing. Therefore, the ICI data will be biased high due to the fact that the method detection limits will be higher (due to shorter run times collecting less gas sample). Any congener reported as ND will be entered into EPA's databases with higher concentrations relative to the EGU dataset. Given that the Toxic Equivalency Factor (TEF) methodology weights some congeners as much as 1000 times others, a high detection limit for one of the highly weighted congeners (such as 2,3,7,8 TCDD) for the ICI data set relative to the EGU dataset could skew the estimated emissions considerably. It is simply not possible to obtain a fair comparison and EPA's judgment that the ICI coal boilers' D/F emissions are significantly higher than the EGU boilers is not supported with facts.

EPA observes that a significant majority of the EGU test runs were at or below MDL even with 8 hour test runs. However, because EPA did not require 8 hour test runs for the ICI boiler testing, it does not know what majority of ICI boiler test runs would also be below the MDL with the extended test runs.

Finally, EPA's statement *that "Overall, the available test methods are technically challenged, to the point of providing results that are questionable for all of the organic HAP"* is equally as true for ICI boiler sources as EPA concludes it is for EGUs. While not as lengthy as 8 hour runs used in the EGU ICR, these four hour runs require two days of testing and offer significant challenges in terms of cost and feasibility. The fact that much of the reported data is "flagged" with high uncertainty is further evidence that the results of D/F testing for boilers are questionable and supports EPA's work practice approach for EGUs.

EPA has ample justification to not set numerical emission standards for D/F for utility boilers and it should handle ICI boilers the same. In summary, this is due to the high levels of uncertainty associated with much of the reported data used to set the final numerical standards and the difficulties in obtaining reliable data to demonstrate compliance.

IV. CIBO Supports EPA's approach to CO and THC and it should be adapted to the Boiler MACT Rule as well.

CIBO supports EPA's findings and approach to CO and THC in the Utility MACT rule. EPA stated that they "did not have emissions test results that would provide data for emissions of a variety of pollutants," including CO and THC. 76 Fed. Reg. 25,022. When conducting tests on CO and THC, EPA found that:

> The average CO from the pilot-scale tests ranged from 23 to 137 ppm for the bituminous coals tests, from 43 to 48 ppm for the subbituminous coal tests and from 93 to 129 ppm for the Gulf Coast lignite tests. However, it was difficult to correlate that concentration to the quantity of organics produced for several reasons. The most difficult problems are associated with the large number of potential organics that can be produced (both those on the HAP list and those that are not on the HAP list). This is further complicated by the organic compounds tending to be at or below the MDL in coal combustion flue gas samples… In the pilot tests, the THC measurement was inadequate as the detection limit of the instrument was much too high to detect changes in the very low concentrations of hydrocarbons in the flue gas.

76 Fed. Reg. 25,039.

Setting no standard for CO and THC is correct given the data provided, and there is no justification for not taking the same precautions in setting standards for ICI Boilers, even if only for coal and liquid units. EPA should not set numeric standards based on questionable data, which is harmful to sources needing to comply and not defensible for the Agency.

V. Certain provisions should be revised to ensure that the Rule applies properly to coal refuse-fired CFB combustion units, based on the mandates of the CAA.

A. The definition of coal refuse should be revised.

The definition of “coal refuse” under the Proposed Rule should be revised by eliminating the restrictions on heating value and ash content, consistent with the definition of this term in the NSPS for fossil fuel-fired steam generators and electric utility steam generating units. Revising the Proposed Rule in this way will serve to clarify that coal refuse material with a heating value greater than 6,000 Btu/lb is properly considered “coal refuse” under the MACT standard. The definition of coal refuse is problematic for many waste coal plants. They burn coal refuse with BTUs greater than 6,000 BTUs per pound. The Waste Coal Plants that are classified as Qualifying Facilities either as Independent Power Production Facility or Cogeneration Facility burning waste coal had their fuel supply certified by FERC.

In the Preamble, EPA reiterates its position, as originally stated in the recent final rule, “Identification of Non-Hazardous Secondary Materials That are Solid Waste”, 76 Fed. Reg. 15,456 (Mar. 21, 2011) (to be codified at 40 C.F.R. pt. 241) (NHSM Rule), that currently-mined coal refuse should not be considered a solid waste under the Resource Conservation and Recovery Act (RCRA), as long as it is not discarded. 76 Fed. Reg. 25,026. By contrast, in that same rule, legacy coal refuse is not treated as a fuel, but qualifies as a solid waste in the first instance, because it has been discarded. Id. The NHSM Rule makes clear, however, that if legacy coal refuse is processed in the same manner as currently-mined coal refuse, the legacy coal refuse would not be a solid waste at the point of combustion, and therefore the combustion of such material would not be subject to regulation under CAA Section 129. Instead, the relevant combustion unit would be subject to the Utility MACT regulation, if the unit meets the definition of EGU. Id.

B. Coal-fired EGU subcategories should be clarified.

The proposed provisions relating to the two subcategories for coal-fired EGUs should be revised to clarify that an EGU combusting coal refuse with a heating value of less than 8,300 Btu/lb on a dry basis is regulated as a coal-fired EGU under the Utility MACT in accordance with the emission standards applicable to sources combusting coal exhibiting such lower heat content.

EPA has created only two categories coal: > 8300 Btus Ash Free Moisture Free and < 8300 Btus Ash Free Moisture Free virgin non-agglomerating coal. Most anthracite and bituminous waste coal (coal refuse) would have a heating value > 8300 Btus.

The Proposed Rule defines coal refuse, in relevant part, as having “a heating value less than . . . 6,000[Btu/lb] on a dry basis” (emphasis added). Id. at 25,122. On its face, this definition appears to indicate that a CFB unit combusting coal refuse cannot fit within the subcategory of sources comprising “unit[s] designed for coal > 8,300 Btu/lb” because the heating value of coal refuse is, by definition, too low. It follows then, that, in order for a coal-refuse fired EGU to be subject to the Proposed Rule, such unit must fall within the only other subcategory for coal-fired EGUs – i.e., a combustion unit designed for coal < 8,300 Btu/lb.

However, the “unit designed for coal < 8,300 Btu/lb subcategory” is defined as including, in relevant part, “any EGU designed to burn a nonagglomerating virgin coal” (emphasis added). This definition would appear to exclude coal refuse, on the basis that coal refuse is generally considered to be distinct from virgin coal. Indeed, in the NHSM Rule, EPA takes the position that coal refuse and virgin coal are two different materials. *See* 76 Fed. Reg. 15,509. For these reasons, it is unclear how a coal refuse-fired combustion unit would be characterized for purposes of the Proposed Rule, because such a unit does not appear to fit within either subcategory for coal-fired EGUs under the Proposed Rule.

Thus, EPA should resolve inconsistencies in its treatment of coal, coal refuse and solid waste.

C. An EGU that has been determined to be low emitting (LEE) for mercury should not be subject to unreasonably burdensome requirements for demonstrating continuous compliance.

The compliance demonstration requirements applicable to EGUs qualifying as low-emitting EGUs (LEE) for mercury should be made less burdensome. More specifically, LEEs with mercury emissions below 50% of either of the proposed LEE thresholds should be authorized to demonstrate continuous compliance through annual stack testing, and should not be required to conduct monthly fuel analyses. Under the Proposed Rule, existing EGUs may qualify for LEE status for mercury if their mercury emissions are less than 10 percent of the applicable mercury emissions limitation, or less than 22.0 pounds per year. 76 Fed. Reg. 25,106. Because the mercury emissions of a unit with LEE status are very low, LEE units should not be subject to unduly burdensome continuous compliance requirements. LEE-status units must perform monthly fuel analyses to demonstrate continuous compliance with emission limits, provided the unit operates within the operating limits established during the initial performance test. 76 Fed. Reg. 25,106. This unduly burdens sources. Instead, the

Rule should provide less onerous compliance demonstration methods for sources establishing mercury emission rates meaningfully below the LEE thresholds.

We suggest a less onerous mercury compliance demonstration such as the following: If a unit shows through performance testing mercury emission rates less than 50 percent of either applicable LEE thresholds, the unit would be a very low emitting EGU. That unit would have the option to demonstrate continuous compliance through annual performance testing only, and not be required to conduct monthly fuel analyses as long as the fuel supplier does not change. Annual testing could consist of three 120-minute test runs performed using EPA Method 30B. Sources emitting at very low mercury emission rates are highly unlikely to show emissions that would exceed the LEE threshold.

D. The proposed HCl emission limit for existing coal-fired EGUs should be revised consistent with an appropriate health-based analysis for this pollutant.

For existing coal-fired EGUs, the Proposed Rule identifies emission limits for mercury, hydrogen chloride ("HCl") (or sulfur dioxide ("SO2"), as a surrogate for hydrogen chloride), and total non-Mercury HAP (or total particulate matter ("PM"), or individual HAP metals, as surrogates for total non-mercury HAP). Although coal refuse-fired CFB units (and perhaps others) achieve very low mercury emission rates, and most would likely even satisfy the stringent applicable emission limits for mercury under the Proposed Rule, these clean-burning units generally could not simultaneously meet the proposed limits for HCl. In this respect, the proposed emission limitation for HCl is inappropriately stringent and inconsistent with statutory directives for establishing HAP emission standards.

The incorrect proposed HCl emission limit identified in the Proposed Rule apparently results from EPA's use of an improper methodology in developing the emission limits under the Proposed Rule. First, the proposed HCl emission limit fails to reflect the relationship between the control of this pollutant and the simultaneous control of mercury emissions. Specifically, at facilities that combust coal refuse (e.g., waste coal plants), the relatively high levels of chlorine in the fuel promote the formation of oxidized mercury, which can be readily controlled by a baghouse. By reducing the amount of HCl (and therefore chlorine) in the flue gas, as would be required in order to satisfy the stringent HCl standard under the Proposed Rule, the extent of oxidation of mercury (and therefore the efficiency of mercury control through the baghouse) would also be reduced, resulting in an overall reduction in mercury control efficiency. Accordingly, a proposed regulatory scheme that requires significant reductions in HCl emissions, but does not account for the direct relationship between the presence of chlorine and a facility's ability to control mercury, may have the unintended result of increasing mercury emissions as a consequence of reducing HCl emissions.

In addition, in deriving the proposed emission limits, EPA evaluated the lowest emission rates achieved by individual sources on a pollutant-specific basis, without consideration of whether the same affected EGU could simultaneously satisfy all of the proposed emission limits that would apply to that unit under the Proposed Rule. For example, in one step, EPA considered whether an affected coal-fired EGU would be capable of meeting the proposed emission limit for mercury, without consideration of the unit's simultaneous emission rates for either HCl or total non-mercury HAP. In a separate step, EPA analyzed proposed emission limits for HCl based on the lowest emission rates achieved for that pollutant from distinct affected coal-fired EGUs, without considering simultaneous emission levels of mercury and total non-mercury HAP from such sources. Therefore, while EPA's proposed emission limits reportedly reflect emission levels achieved by the lowest emitting sources in the source category, EPA did not identify existing sources that simultaneously achieved emission standards for all HAPs that would be governed by the Proposed Rule. For this reason, EPA's derivation of the emission limits proposed in the Proposed Rule, including, in particular, the proposed emission limit for HCl, fails to satisfy the mandates of Section 112 governing HAP emission limit development.

Further, the proposed HCl emission limit fails to reflect the unique nature of coal refuse-fired EGUs utilizing CFB combustion technology in several ways. First, in developing the HCl emissions standard under the Proposed Rule, EPA failed to consider any coal refuse-fired CFB units and, therefore, did not even evaluate any EGUs that employ CFB technology. EPA clearly recognized the distinguishing characteristics of CFB technology in the context of developing the recently-promulgated MACT standards for industrial, commercial, and institutional boilers, by establishing a specific subcategory of existing coal-fired units for circulating fluidized bed boilers. See National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers", 76 Fed. Reg. 15,689 (to be codified at 40 C.F.R. pt. 63, Subpart DDDDD) (the "Boiler MACT"). Second, there have been no commercially demonstrated applications of dry sorbent injection for the control of HCl from coal refuse-fired CFB units.

E. Filterable PM – not total PM – should be used as a surrogate for non-HG HAP metals. EPA has proposed the use of total PM (filterable PM plus condensable PM) as an appropriate surrogate for the non-Hg HAP metals. However, as other commenters have pointed out in detail, EPA has failed to demonstrate a consistent and direct connection between total PM measured during stack testing and filterable PM monitored using a CEMS across all operating conditions for all affected sources. Rather, non-Hg metal HAP emissions appear to be better correlated with filterable PM, and the Rule should be revised to establish a filterable PM limit as a surrogate for total non-Hg HAP metals.

Another reason to regulate filterable PM instead of total PM is that PM CEMS, which are proposed as compliance monitoring, measure only filterable PM. However, the proposed rule requires units to maintain the PM concentration at or below the highest 1-hour average measured during the most recent performance test demonstrating compliance with the total PM emissions limitation (76 Fed. Reg. 25129, Table 4). This is an illogical requirement and should be changed so that the emission limit is actually a supportable filterable PM limit on an equivalent basis as the PM total limit. To promulgate the requirement as proposed imposes a de facto unjustified reduction in emission limit on those units using a PM CEMS.

VI. Certain proposed NSPS revisions, which include revisions to Subparts Db and Dc, should be revised; CIBO supports some other NSPS revisions.

The NSPS revisions affect sources constructed or modified after May 3, 2011. Most of the proposed NSPS revisions cover Da, but some also apply to Db and Dc.

A. In the proposed NSPS revisions, EPA has stated that the revised PM standard will be total PM (filterable plus condensable) to address control of PM2.5. EPA is proposing to not establish separate PM10 or PM2.5 standard because measurement would be difficult with wet stacks (there is currently no viable test method to determine the size fraction of the filterable PM for stacks that contain water droplets) and many units are expected to use wet scrubber or WESP as part of their compliance approach. 76 Fed. Reg. 25060. CIBO agrees that a separate filterable PM2.5 or condensable PM standard should not be established due to both measurement issues and also because control technologies installed for total PM, and also for NO_x and HCl/SO_2, will result in reductions of both direct PM2.5 and PM2.5 precursors.

B. EPA has not provided separate standards for periods of startup, shutdown and malfunction (SSM). EPA has taken inconsistent approaches to a circumstance common to EGU and ICI boilers, and EPA should treat these circumstances with the same legal rationale and mechanisms. CIBO is concerned about EPA's erroneous factual conclusions regarding SSM periods as well as its interpretation of CAA 112(h), which imposes a serious, unavoidable compliance risk for regulated sources for no justifiable reason.

For startup and shutdown, EPA asserts that utility boilers do not start up or shut down frequently. The frequency of SS periods is immaterial to the standard to be applied to these circumstances. The Clean Air Act is unambiguous on this point: work practice standards are the remedy for standard-setting where it is not "not feasible to prescribe or enforce an emission standard," including where "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." CAA 112(h).

EPA also claims that the standards, applicable at all times, account for SS periods. But then EPA reverses the burden, and directs sources to prove through data that units cannot meet the limits during SS periods. In the Boiler MACT rule, EPA imposed this same burden to prove a negative on the ICI boiler sector, which defies all logic. It is because measurement of data "is not practicable due to technological and economic limitations" that data generally are unavailable to prove the negative. EPA should resolve this issue in this rulemaking consistently with the approach it ultimately took in the Boiler MACT rule, and provide work practice standards during SS periods.

Regarding malfunction events, the rule fails to establish numeric or work practice standards for these events, which are known to occur even when sources are being operated using best practices. Instead, EPA provides that sources must affirmatively defend their handling of a malfunction pursuant to a long list of subjective criteria in the rule and EPA's determination of failure on even one criterion results in the malfunction event being declared an emission violation. CIBO opposed this approach in the boiler MACT rule, and opposes it here for the same reasons. Malfunctions are distinct operating modes, notwithstanding EPA's assertion to the contrary, and should be properly provided for through standards. These events are known to occur and avoided assiduously by sources due to their danger to personnel and billion-dollar investments in equipment. Congress anticipated these events when drafting the CAA and provided 112(h) for just these circumstances. EPA now deviates from the CAA to establish by regulation a highly subjective regulatory approach that leaves sources unjustifiably exposed to possible compliance violations where they simply cannot be avoided.

CIBO supports work practices for SS, as in the Boiler MACT rule, and work practices for M also, which is not provided in the Boiler MACT rule, but should be on reconsideration.

C. EPA is proposing to exempt natural gas-fired boilers from NSPS PM and opacity limits. 76 Fed. Reg. 25062. In the same manner in which we support EPA's determination that HAP limits for industrial gas-fired boilers are not necessary under the Industrial Boiler MACT, we also support EPA's proposal to exclude gas-fired EGUs from regulation under the Utility MACT and to exempt natural gas-fired EGUs from the PM and opacity standards under NSPS. Limiting the regulatory burden for gas-fired boilers encourages the use of this clean fuel and acknowledges that PM and HAP emissions from gas-fired boilers are minimal and not cost effective to regulate.

D. EPA is proposing to exempt large MWCs covered under NSPS Db from NSPS Da; exempt NSPS CCCC-covered CISWI from NSPS Da, Db, and Dc; exempt NSPS BB-covered recovery furnaces from PM standards under NSPS Db; and exempt NSPS Ja-covered fuel gas combustion devices from SO2 standards under NSPS Db. 76 Fed. Reg. 25062. CIBO supports regulatory streamlining wherever possible in order to reduce the regulatory burden on sources already subject to multiple regulatory requirements. For example, NSPS Subpart BB recovery furnaces are already subject to PM limits under MACT Subpart MM, are well controlled for PM as all are equipped with ESPs, and PM requirements under NSPS Subpart Db are not necessary.

E. The rule expands the definition of distillate oil in Db and Dc to include kerosene and biodiesel. CIBO supports this expansion, which provides clarity.

F. Adding provisions to D, Da, Db, Dc to allow parameter monitoring instead of COMS.
CIBO supports these changes.

If you have any questions concerning our comments or require clarification, please contact me at 703.250.9042. Thank you for your consideration.

Sincerely yours,

/s/ Robert D. Bessette

Robert D. Bessette
President