Representing the Interests of America's Industrial Energy Users since 1978

May 20, 2011

The Honorable Lisa P. Jackson, Administrator
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Mail Code: 1101A
Washington, DC 20460

RE: Petition for Reconsideration of the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT Rule), 76 Fed. Reg. 15,554 (Mar. 21, 2011) (Docket No. EPA–HQ–OAR–2002–0058).

Dear Administrator Jackson:

INTRODUCTION

Pursuant to § 307(d)(7)(B) of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B) and for the reasons set forth below, the Council of Industrial Boiler Owners (CIBO) petitions the Administrator of the United States Environmental Protection Agency (EPA) to reconsider specific provisions in its final rule, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT Rule), 76 Fed. Reg. 15,554 (Mar. 21, 2011).

CIBO is a broad-based association of industrial boiler owners, architect-engineers, related equipment manufacturers, and university affiliates with 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.

On June 4, 2010, EPA proposed the rule National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (75 Fed. Reg. 32,006). On August 23, 2010, the comment period closed. On March 21, 2011, EPA published the final Boiler MACT Rule (76 Fed. Reg. 15,554).

Reconsideration of the rule is warranted because the grounds for the issues identified below, which are "of central relevance to the outcome of the rule," arose after the public comment period or could not be raised due to impracticability. 42 U.S.C. § 7607(d)(7)(B). Considering this, the Clean Air Act (CAA) requires that EPA "shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed." Id. Furthermore, during the reconsideration of the rule, EPA may stay the effectiveness of the rule. Id.

CIBO respectfully requests that EPA grant reconsideration of the following issues.

I. STANDARDS

A. Gas 2

In the final Boiler MACT rule, EPA included a new definition of "other Gas 1 fuel" that provides the ability for units firing other gaseous fuels to utilize the work practice approach of Gas 1 units if they have a mercury content of no higher than 40 ug/m3 and H2S content no higher than 4 ppmv. 76 Fed. Reg. 15,685. If those concentrations are exceeded, units firing those other gases are considered "units designed to burn Gas 2 (other) gases" subject to the established emission limits.

EPA stated in the preamble in its response to comments, "EPA has determined that to the extent that process gases are comparable to natural gas and refinery gas, combustion of those gases in boilers and process heaters should be subject to the same standards as combustion of natural gas and refinery gas." 76 Fed. Reg. 15,639. EPA also noted that the Hg and H2S limits were based on data which EPA determined was available for natural gas. The basis for establishing the gas specifications is provided in the ERG docket document *Gas Specification for Industrial, Commercial, and Institutional Boilers and Process Heaters National Emissions Standards for Hazardous Pollutants- Major Source,* January 2011.

However, EPA stated (as noted above) that their intent was to consider other gases that are similar to natural gas and refinery gas as comparable, and to thereby be subject to the same standards as combustion of natural gas and refinery gas. That being the case, at the very least EPA should be using the fuel quality data in their MACT database and allow other gas H2S content to reflect concentrations seen in refinery gas. The MACT database includes 99 refinery gas analyses for percent sulfur (H2S was not specifically provided in any analyses). Equivalent sulfur content ranges from 0 to 300 ppmv with an average of all reported analyses indicating 10

ppmv. If the two analyses at 300 ppmv are excluded as potential outliers, the maximum reported sulfur content is 18 ppmv. Therefore, with this significant quantity of data available, it is logical for EPA as a basic approach to include consideration of this level of sulfur (and implied H2S concentration) to be allowable for other gas 1 fuels.

An attempt was made to review the MACT database to observe the reported natural gas Hg and H2S content. However, there were significant errors noticed in the data. For example, of the 94 reported natural gas sulfur analyses, 53 were actually not natural gas or were incorrect compared to company-reported ICR data. Of the 43 Hg listed analyses, 28 were not for natural gas. Specifically, PASuperiorTubeCo analyses were actually for Residual Oil; PABayValleyFoods and TNOakRidge analyses were actually for coal; TXHuntsman sulfur analyses were reported in grains per 100 scf but input to the database as percent; and VADominion data was reported in ppm but input as percent. The valid natural gas sulfur analyses appeared to indicate <2 ppm sulfur. But these major errors demonstrate the significant issues remaining in the EPA database, and raise serious questions regarding the validity of the data upon which EPA is basing its regulatory determinations. Such obvious errors may also be prevalent in other datasets. Therefore, this supports the need for further reconsideration by EPA.

In addition to the above use of EPA's own fuel quality data, EPA should set the Hg and H2S criteria for gas 2 to be equivalent to gas 1 with full recognition of the EPA-allowable H2S concentration under the Refinery standards. Based on the sulfur standards for refinery fuel gas under 60.104(a)(1), the H2S specification for other gas 1 fuel should be similar to the standard established under that rule of 0.10 gr/dscf (162 ppm). Because refinery gas is fully within the scope of gas 1 quality, and EPA has stated that to the extent that process gases are comparable to natural gas and refinery gas, combustion of those gases in boilers and process heaters should be subject to the same standards as combustion of natural gas and refinery gas, then it logically follows that the criteria for other gases need to be of comparable quality to refinery gas and the H2S threshold must be set at 162 ppmv.

B. Dioxin/Furan

The D/F emission standards included in the final Boiler Rule are unachievable for many boilers. It appears that this is due in part to several errors made in setting the D/F emission standards and the fact that the data relied on is highly uncertain. Considering this, EPA should address the issues discussed below during the administrative reconsideration process. CIBO suggests that EPA set a work practice standard instead of numerical limits.

(1) EPA Did Not Properly Address Uncertainty in the D/F Data.

Much of the data relied on by EPA in setting the D/F emission standards are highly uncertain. Considering this, EPA should set a work practice standard instead of numerical limits. In EPA's recently signed Utility MACT, it draws the following conclusions regarding the regulation of D/Fs 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.

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. A CIBO member Eastman's data for its Boiler 30 reveals a further understanding of the uncertainty.

The laboratory report for the Eastman boiler, which is not a top performer, is enclosed. See Analytical Perspectives Report on the Eastman – Kingsport Boiler, (Sept. 16, 2009) (Attached). 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.

(2) ICIs 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/Fs 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

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 since sulfur content ranges from 0.5 percent to about 6 percent and chlorine is usually less than 1,000 ppm.

(3) EPA's Reasoning for Applying Numerical 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/Fs 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 has not been adequately 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, since 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 (as CIBO points out elsewhere) that much of the reported data is "flagged" with high uncertainty is further evidence that the results of D/F testing for ICI boilers are questionable. Given that much of the reported values for the various congeners are flagged could lead some ICI boiler owners to elect to attempt 8 hour test runs in order to improve the accuracy and lower the end result. In this case, the testing is clearly impracticable and unreasonable.

Just as it proposed in the Utility MACT, EPA has ample justification to choose not to set numerical emission standards for D/F for industrial boilers and process heaters. In summary, this is due to the high levels of uncertainty associated with much of the reported data used to set the final rule's numerical standards and the similar difficulties commercial, industrial, and institutional sources will face in obtaining reliable data to demonstrate compliance.

(4) EPA's Cost Estimate for Meeting the D/F Numerical Standards are Not Valid.

A review of the preamble and background support documentation in the docket reveal statements by EPA which indicate EPA does not believe the D/F limits in the final rule will be problematic or costly for sources to meet. Therefore, EPA apparently believes the standards are reasonable and lawful. First, in the Response to Comments document, EPA had the following statement in its response to a comment requesting the D/Fs be made eligible for emissions averaging:

> Further, both CO and dioxin/furan emissions are formed through combustion and not and it is important for the Agency to promote good combustion on all units. Most of the limits are expected to be achieved with good combustion and combustion controls instead of add-on pollution controls and so the concerns with costs of compliance are less than those associated with PM, HCl, and Hg which often require add-on controls to be installed on individual units. (reference Response to Comment EPA-HQ-OAR-2002-0058-2801.1, excerpt number 36).

EPA has no data to support that good combustion and combustion controls would lower D/F formation from industrial boilers and process heaters. This statement is merely conjecture and not supported with facts or data. Much work and costly testing would have to be done to establish if combustion controls would, in fact, reduce D/F emissions to the final rule's standards. If a source pursues this approach only to find there is no reliable combustion control strategy to comply with the standard, then the source is left without enough time to then research, test, design, and install a post-combustion control strategy to meet the standard by the compliance date (even with a one year extension). Also, EPA has not considered that combustion controls aimed at reducing D/F formation (i.e. hotter flame zones) will often run counter to previous efforts by sources to install low NOx combustion control systems (e.g. low NOx burners, over-fire air) as part of state and federal ozone control programs. Such sources would then have to install a post-combustion control such as selective non-catalytic reduction (SNCR) to compensate for reversals of previous NOx reduction systems. So, for EPA to think

that D/F reductions utilizing unproven combustion control strategies will come at little or no cost is simply misguided and does not reflect reality.

Second, in the background document, "Revised Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source", EPA has the following discussion relating to its assumptions for the costs to meet the D/F standards:

> The final rule requires all units that measure dioxin data below the method detection level to report that congener as zero. Based on the reported dioxin/furan data and associated detection levels available at the time of the final rule, most units will fall below the MACT floor levels if the non-detect congeners are treated as zero. For coal, 17 of the 27 tests would meet the existing limits, 17 of the 22 tests for biomass would meet the existing limits, and all of the liquid and process gas tests would meet the existing limits. Given these results and the fact that some units are installing ACI for mercury control, which is expected to have a co-benefit of reducing dioxin/furan emissions, the cost analysis does not estimate any control costs for achieving the dioxin/furan emission limits.

This discussion conflicts with the previous statement discussed above. Here, EPA is assuming that activated carbon systems will be installed for mercury and that these systems will also reduce D/F emissions. EPA has no data to support this assumption that ACI systems designed to reduce mercury are going to also reduce D/Fs. This again is mere conjecture. While ACI has been used on some municipal waste and hazardous waste incinerators to reduce D/Fs, those are entirely different cases than a fossil or biomass fuel boiler. The levels of D/Fs found in these cases are many times higher than the levels for boilers found in EPA's dataset. No research or field studies have been done to demonstrate the effectiveness (if any) or annual operating cost of ACI systems on D/F concentrations so low and close to detection levels as those found in boilers and process heaters.

EPA also is basing its assumptions that sources will incur no costs to meet D/F standards by either (1) utilizing "free" combustion controls (which is not the case as discussed above) or (2) getting co-benefits from ACI systems installed to reduce mercury emissions. This, again, is mere conjecture. For example, work done by one CIBO member company (while preparing for the now vacated Boiler MACT), showed that ACI is not effective in controlling mercury from coal-fired stoker boilers. EPA states in the Utility MACT preamble (page 214) that ACI is not very effective on boilers burning high sulfur coals. So, even if ACI would be effective at D/F control, it is not a foregone conclusion that those systems will be installed absent a need to reduce D/Fs. Further confounding EPA's logic is the fact that for ACI to be effective, a downstream fabric filter is needed since the fabric filter provides additional residence time for adsorption to occur (otherwise, extremely high carbon injection rates are needed to obtain good performance of the system). Many boilers have existing ESPs rather than fabric filters. Some units equipped with ESPs can meet the particulate matter standard, and will not plan upgrades to FFs. And because it is less capital intensive to upgrade ESPs than to replace them with FFs, many units that are close to meeting the PM standard with ESPs will avoid installation of FFs.

Many sources with such configurations will likely choose dry sorbent injection (duct or furnace injection) to meet the HCl standard (if they have higher chlorine coal supplies), and will likely avoid the costly upgrades to fabric filters. Therefore, there will be fewer configurations where ACI is already incorporated than EPA has assumed.

One member company has a pulverized coal boiler equipped with a spray dryer absorber and an electrostatic precipitator (ESP). Available test data for this boiler shows it to be capable of meeting the particulate matter, mercury, HCl, and CO emission limits with no modification. However, the one D/F stack test shows it to not meet the D/F standard, even when substituting zeros for the congeners that were not detected. The one stack test data shows the D/F emission rate at about 0.005 ng/dscm TEQ - just above the standard. This boiler is equipped with low-NOx firing system with over-fire air for NOx control. The source has no data to inform it if a change in combustion conditions would reduce D/Fs, although discussions with the boiler OEM suggest that D/F formation could be limited by the geometry of the boiler's furnace. Even if it had such data, it would likely have to invest significant capital to install SNCR to compensate for the increased NOx emissions caused by a change in combustion operating conditions. The source also has no data to inform it if ACI, possibly in tandem with a conversion of the ESP to a Fabric Filter (FF), would reduce D/Fs at the extremely low levels that are present. Even if it had such data, the source would incur significant additional capital costs and annual operating and maintenance costs to comply with the D/F standard. The source is thus faced with choosing between two capital-intensive approaches to control D/F, but with little assurance that either approach would be technically capable of complying with the standard. This example may reasonably be assumed to represent a large number of industrial boilers equipped with low-NOx firing systems, and demonstrates that EPA's assumption of no incremental cost for D/F control is incorrect.

In summary, effectiveness of control strategies on D/F emissions from boilers and process heaters is a huge unknown. This alone is justification for a stay and reconsideration of the final rule so definitive control options can be identified and installed within the 3 year compliance window. Further, even if these strategies were known to work, they would add substantial cost to the final rule and certainly would not result in no incremental cost as EPA has assumed. Sources would be adding ACI systems and fabric filters which would not otherwise be required. Alternatively, they would be adding post-combustion NOx control systems to compensate for reversals of low-NOx combustion control strategies.

(5) EPA Did Not Follow its Recommended Approach to Adjust dioxin/furan Emission Limits for Detection Level Limited Data.

EPA explains on page 14-15 of its MACT Floor memo its procedure for accounting for measurement detection level variability when calculating the MACT floor emission limits. Essentially, EPA explains that it establishes a "representative detection level" (RDL) for each data set and uses this value to ensure the emission limit adequately accounts for measurement variability. It does this by comparing a value of three times the RDL to the computed floor value (e.g. the 99 percent confidence UPL) and setting the floor no lower than three times the RDL.

A review of Excel spreadsheet in EPA's Appendix D (Analysis of Representative Method Detection Level) to the MACT Floor memo shows that EPA did not follow the procedure described in the narrative. Taking pulverized coal boilers as an example, when EPA corrects its calculations, the emission standard of 0.004 ng/dscm would be changed to 0.012 ng/dscm. In this case (and it appears EPA made these same errors on other subcategories as well), EPA made no corrections to account for measurement variability. As can be seen from tab D-2b, column F, EPA found that 3xRDL was "Not Applicable" for all of the test runs of the top performers.

First, EPA compared apples and oranges by comparing the sum of the average TEQ adjusted RDL for the seventeen isomers of D/Fs for each run to the average of the 17 isomers over all the test runs for all of the top performers. In other words, the RDLs were being compared to a test value that was low by a factor of 17 (also, EPA should have been comparing 3 times the RDL, not the RDL) to the test run values). Secondly, EPA tested to see if the RDL for each test run is less than the average of the concentration of the 17 isomers over all the test runs for all of the top performers. What EPA should have done was multiply each value in column D (the TEQ adjusted RDL for each test run) by 3 and test to see if that value (3xRDL) is greater than the average of the sum of the 17 isomers for each of the test runs from the top performers. The result would be that 3xRDL is greater and would be used in lieu of the test run values for all six runs of the top performers to calculate the UPL. When making these substitutions, the standard would be effectively tripled.

C. PM Limits for New Solid Fuel Fired Boilers

The previous proposed limit for new unit PM was 0.008 lb/mmbtu. The final standard of 0.0011 lb/mmbtu is a reduction of over 80%. This level of emission reduction has not been demonstrated to be achievable by industrial applications, and may only be achievable on a consistent basis with the use of new technology not commonly used in industrial applications. Electrostatic precipitator suppliers and bag house suppliers both indicate that this new standard is not achievable with the exception that the type of exotic filters used for clean rooms in food production and some pharmaceuticals may be applicable but at exorbitant cost.

The best stack test PM emissions are 0.02 with new baghouse installation. EPA needs to revisit this issue during administrative reconsideration. Specifically, EPA should focus on incorporating variability in the ana;ysis as required by the CAA § 112.

D. Emission Testing Requirements Should Be Changed to Be Consistent With the 5-year Title V Permit Review Cycle.

A significant amount of testing will be required by sources to determine the compliance status with respect to the rule and to evaluate and select available control strategies. Capital projects to install necessary control equipment cannot proceed until the testing and evaluation is complete. Due to the high number of sources affected by the rule that have the same concerns, it is likely that availability of stack testing personnel and laboratory facilities to conduct tests will be limited, adding to the time required to complete this essential first step. As outlined below, annual compliance testing requiring multiple test runs for purposes of compliance will further reduce the availability of testing and laboratory resources.

EPA acknowledges that the cost of testing small boilers and process heaters is prohibitive. While the cost of emissions testing larger units is less prohibitive, EPA must consider these costs when establishing the frequency of testing.

The benefits of testing more frequently than every 5 years do not justify the costs. HAP emissions change only when operating parameters change (e.g., firing rate, maximum contaminant input limits for chloride and mercury, type of fuel, combustion efficiency, oxygen content, etc.) or when design changes occur. Absent these changes to an affected source, operating parameters established by implementation of Boiler MACT are more than sufficient to ensure that emissions will not significantly change over time. Furthermore, the Boiler MACT provisions require owners and operators to install continuous emission monitors to measure real-time emissions (oxygen and PM), measure and monitor prescriptive operating limits, as well as monitor, measure, and keep records of each type of fuel on a continuous basis to verify compliance with limits established during the compliance test. The Boiler MACT regulations also stipulate that sources must perform testing under a representative operating load and require sources to maintain within 110% of the average operating load observed during testing. Based on these stringent monitoring requirements, the operating parameters established during testing are sufficient for a source to demonstrate compliance for a 5-year period. Modifications will be tested under the provisions for new and modified sources, and do not need to be considered in ongoing test requirements.

EPA has underestimated the cost of emissions testing necessary to comply with Boiler MACT. Typical industrial boilers combust a variety types of fuels. This practice is necessary for industry to maintain competitive fuel pricing. For example, typical coals burned in an industrial boiler are highly variable. To account for this variability, sources would be required to perform multiple compliance tests every year. In many cases, the worst case coal for Hg is not necessarily the worst case coal for HCl, and therefore a separate compliance test is required for each fuel. In the preamble to the rule, EPA cites, industry average costs per compliance test ranging from $60,000 to $90,000 per test. In many cases, however, sources will be required to perform 2 to 3 or even more tests to provide data on the range of fuels being combusted. These annual compliance testing costs of $120,000 to $270,000 are unreasonable and do not take into consideration the monetary impact associated with the identification and investigation of new fuel sources. In addition, testing annually requires an exorbitant amount of company resources to plan, schedule, and perform the required testing which have not been included in the above mentioned cost estimates.

Other regulations support a 5-year testing cycle. For example, 40 CFR §75 requires low mass emissions units to establish NOx emissions curves based on testing conducted every 5 years. Several states require that testing be conducted upon each 5-year Title V permit renewal. All affected major sources subject to Boiler MACT are required to have Title V Permits. The Title V permitting program provides the appropriate vehicle to implement a 5-year test requirement.

E. EPA's Denial of the Request for an Alternative Total Hydrocarbon (THC) Emission Standard is Unsupported, Arbitrary and Capricious.

One CIBO member company (Eastman) requested that EPA set an alternative THC limit. The company's comment and response from EPA to this comment is shown below:

> Commenter Name: Stephen R. Gossett
> Commenter Affiliation: Eastman Chemical Company
> Document Control Number: EPA-HQ-OAR-2002-0058-3137.1
> Comment Excerpt Number: 16
> Comment: Total hydrocarbons (THC) needs to be added as an alternative standard to CO as a surrogate for non-dioxin organic HAPs.
>
> EPA has elected to propose CO as a surrogate for non-dioxin organic HAPs and is requiring CO CEMS for units larger than 100 mmBtu/hr. Compliance with the CO emission standard is then determined on a 30 operating day rolling average basis. While we have concerns that the MACT floor emission limitations do not properly account for load variation or periods of startups and shutdowns, we believe, that once the CO MACT floor level is properly determined, compliance with a CO limit will be the preferred method in many cases. However, Eastman requests that EPA set an alternative THC standard. The Hazardous Waste Combustor MACT (40 CFR 63 Subpart EEE) provides an option of a 100 ppm CO limit or a 10 ppm THC limit. While most hazardous waste incinerator operators selected the CO option, Eastman has selected the THC option at three of our incinerators and have found the THC CEMS, while more costly, to be a workable option.
>
> Also, we have a case where THC may be much preferable to a CO limit. Eastman's largest and newest boiler is a wall-fired PC boiler which was installed with advanced combustion controls (low NOx burners and over-fire air system) to control NOx, plus a Spray Dryer Absorber (SDA) and Fabric Filter for control of acid gases. Preliminary CO CEMS data indicates this boiler will have difficulty attaining the proposed CO limit for PC boilers. Our experience with other solid fuel units shows us that THC levels are often more stable and less reactive to load swings than CO. Since THC really is a better indicator of non-dioxin organic HAPs that CO (CO is not a HAP whereas much of the THCs are HAPs), there is no reason EPA cannot grant our request and provide a THC option. Without the THC option, Eastman is likely to be faced with a very costly choice: either install a capital intensive CO catalytic reduction system; or remove the most modern and most effective combustion controls for NOx at this site to control CO, and install very expensive post-combustion NOx reduction technologies such as Selective Catalytic Reduction (SCR). Please note that industry experience advises against the use of less capital intensive NOx control technologies like Selective Non-Catalytic Reduction (SNCR) on units equipped with SDA's, due to the negative downstream effects of ammonia slip on personnel safety (NH3 release in recycle slurry) and the reliability of downstream components (formation of fouling

ammonium salts). Further note that either of these options will significantly increase system draft loss, which will likely require a new ID fan at considerable expense. Eastman does not believe that the enormous capital expense these options present are justified, given that such a solution reduces CO but may not actually reduce non-dioxin organic HAPs. Eastman believes that this is a classic case of unintended consequences with little commensurate benefit to health or the environment.

Response: *EPA thanks the commenter for their input, but EPA's Office of Research and Development does not support the use of THC as a surrogate for organic HAP from industrial boilers. See preamble for response to comments on how CO limits were modified.*

This response from EPA is unsatisfactory. EPA cannot simply state that is Office of Research and Development does not support THC as a surrogate without providing that logic in the public record. If this is the position of EPA, it unravels the Agency's long history of recognizing that THC is good measure of organic emissions. Traditionally, CO monitoring has been preferred over THC monitoring due to technical and cost issues. Never has the EPA questioned that THC would be a better surrogate than CO, especially since THC is a direct measure of organic emissions. CO is more an indicator of combustion conditions. We note, for example, that the Portland Cement MACT sets standards for THC rather than CO as a surrogate for non-dioxin organic HAPs (40 CFR 63 Subpart LLL, Table 1).

As the commenter states, without a THC alternative (which could likely be met with no controls or operational changes), the company will be spending significant funds to comply with the CO limit. It is reasonable for EPA to provide this alternative and it has precedent for such an alternative in other rules.

II. FLOOR DETERMINATIONS – LIQUID FUELS

EPA used inappropriate methods and data to establish the MACT Floor emission limits for new and existing units. These must be corrected in order to establish a floor which is not arbitrary and biased. Full reconsideration of all liquid emission limits is required. During the administrative petition process, EPA should address the issues outlined below.

A. EPA's Methodology Used in Setting the HCl Floors is Flawed.

EPA proposed emission limits for liquid fuel fired sources in the proposed rule. There were many problems with the units chosen by EPA to be floor units. CIBO comments detailed the problems seen with the floor units relative to the HCl emission limits. While EPA did address most of those comments by revising data and changing the units used to establish the floor for the final rule, upon review of the final rule supporting data from EPA, there are apparent problems with the methodology and data used by EPA to establish the final MACT floors which significantly impact the resultant emission limits.

As provided in the EPA MACT Floor spreadsheets, EPA has identified 88 units with HCl data and 11 units chosen as the floor units. Units 1-7 in the list are all ranked as #1 with each assigned the same minimum test average HCl emission rate of 5.53E-7 lb/MMBtu with the Data Type indicating fuel analysis (FA). Those units are identified as PABoeingRidleyPark units 035, CB4, 031, 036, 037, 039, 053.

Specifically, PABoeingRidleyPark unit 033 is ranked as #12, thus the first unit below (higher emission rate) than the top 11 performing units used to establish the floor. That particular unit has a minimum test average HCl emission rate of 0.000421 lb/MMBtu based on an emission test

The EPA database fuel analysis lists 3 No.6 Residual Oil sample analyses for PABoeingRidleyPark, identified as Samples 1, 2, and 3, with all associated with unit 033. The dates of the samples are 9/23/09, 9/24/09, and 9/25/09 for Samples 1, 2, and 3, respectively. The reported parameter for all 3 samples was chlorine at < 0.01 mg/kg. The HHV for those analyses were listed as 18,603, 18,613, and 18,563 Btu/lb for Samples 1, 2, and 3, respectively. EPA used those HHV values to convert the reported fuel chlorine mg/kg value (detection level) to equivalent HCl as 5.53E-7, 5.52E-7, and 5.54E-7 lb/MMBtu for Samples 1, 2, and 3, respectively. EPA then averaged those values to give 5.53E-7 lb/MMBtu which EPA then applied to all PABoeingRidleyPark units **EXCEPT** unit 033.

Of major significance, EPA ignores the fact that those three No. 6 Residual Fuel Oil samples were coincident with HCl emissions testing on unit 033. Specifically, M26 HCl emissions tests were conducted on 9/23/09, 9/24/09, and 9/25/09 identified as Samples 1, 2, and 3, respectively, so that the respective identified No.6 Residual Oil analyses were taken coincident with those emissions tests. The reported unit 033 HCl emission rates per the Emission Test Template Spreadsheet submitted to EPA by Boeing were 4.76E-4, 3.98E-4, and 3.88E-4 lb/MMBtu for Samples 1, 2, and 3, respectively. Those averaged to 4.21E-4 lb/MMBtu as reported by Boeing. This figure is that listed by EPA in Appendix B, sheet B-5b for unit 033 indicated above.

The required method of compliance for liquid fired units subject to the HCl emission limit is by use of M26 or M26A. Boeing used the correct test method and EPA considers the results valid since they are listed in Appendix B. It is inexplicable that EPA decided to apply the reported fuel analysis data (which reported chlorine content below detection level) to all other units at Boeing when actual emissions testing showed valid results during firing of that fuel. This approach resulted in the actual emissions test results dropping out of the top performer list. Such action on the part of EPA is unconscionable and shows a deliberate attempt to influence the floor setting process to the detriment of the regulated sources. Such an action is even more egregious when it is recognized that two of the Boeing units (053 and CB4) were reported by Boeing in their ICR Phase 1 response Answer Key spreadsheet to actually fire No.2 Distillate Oil, and not No.6 Residual Oil as sampled, analyzed, tested, and reported by Boeing.

As an additional consideration, the SCGPChemRussellville FO Boiler is the #2 ranked top performer for PM emissions and the #4 ranked top performer for CO emissions. That facility reported through the ICR that it burns ultra low sulfur diesel fuel in that unit and reported HCl emissions of 0.002 lb/MMBtu. Ultra low sulfur diesel fuel is essentially the cleanest fuel oil possible and is used for on-road vehicles. No sulfur analysis was provided for that oil, but it

must meet the specification for that type oil, that being <15ppm sulfur. With the final EPA rule emission limits for existing sources, the approach EPA has taken would require units firing the cleanest fuel oil possible to install some type of HCl scrubbing equipment to reduce HCl emissions by an infinitesimal amount. EPA should be obligated to explain how such a rule is justified and why this is not over-reaching.

CIBO recommends that EPA re-evaluate the existing unit HCl floor determination. All PABoeingRidleyPark units assigned the equivalent HCl emission rate based upon the fuel analysis conducted during unit 033 emission tests must be deleted from the list since only the coincident emission test data provides accurate data upon which to base the floor. That will delete ranked units 1-7. EPA must carefully evaluate the next series of units and ensure that all data is accurate and applicable and select new best performing units. Once that has been done, EPA can re-determine an appropriate HCl MACT floor for existing liquid fired units.

The above problem in establishing the existing unit HCl MACT floor extends into the floor emission limit for new liquid fired units, since as identified in Appendix G, the calculated new unit emission limit (3.16E-3 lb/MMBtu) based on TNInvistaChattanooga EU003 Vaporizer #2 emission tests was a higher emission rate than had been determined by EPA for existing liquid fired units, so the new limit was established as equal to the existing unit limit. Therefore, when the existing unit floor limit is re-determined, the new unit limit will be impacted.

In addition, EPA needs to rethink their approach relative to new units. Specifically, the average HCl emission rate during the most recent emission tests by TNInvistaChattanooga EU003 during ICR Phase 2 testing conducted 7/29-30/09 was 0.00062 lb/MMBtu (0.000618, 0.000619, 0.000624 for the three runs). That can be compared to the final new unit emission limit of 0.00033 lb/MMBtu. Therefore, the best performing units that EPA used for determining the new unit emission limit has proven emission rate almost 2x higher than the new unit emission limit. This is an absurd result that simply proves errors in EPA's floor setting methodology.

EPA must re-evaluate the new liquid unit HCl floor determination. Since EPA inexcusably applied extremely low emission rates to top performing existing units as explained above and that influenced the new unit floor setting process, it is possible that the new unit HCl emission limit will actually be correct as determined by the EPA new unit methodology and indicated in Appendix G, i.e., 3.16E-3 lb/MMBtu.

B. EPA's Methodology Used in Setting the Hg Floors is Flawed.

The emission data in the EPA MACT Floor database indicates that >70% of the units with data demonstrate emissions lower than the final existing continental limit. It is believed the ability to meet the limit is really a luck of the draw type of situation since it is wholly dependent on fuel oil quality, which is not under the control of the combustor. EPA does not address the dichotomy of the emission limits imposed compared to the fuels being fired. In fact, EPA ignores fuel differences and maintains all liquids in one subcategory. A key example of the problem set up by EPA is similar to that mentioned above for HCl.

The SCGPChemRussellville FO Boiler is the #2 ranked top performer for PM emissions and the #4 ranked top performer for CO emissions. That facility reported through the ICR that it burns ultra low sulfur diesel fuel in that unit and reported equivalent Hg emissions of 4.9E-5 lb/MMBtu based on fuel analysis. Ultra low sulfur diesel fuel is essentially the cleanest fuel oil possible and is used for on-road vehicles. No sulfur analysis was provided for that oil, but it must meet the specification for that type oil, that being <15ppm sulfur.

The approach EPA has taken in the final rule emission limits for existing sources, units firing the cleanest fuel oil possible would need to install some type of Hg reduction equipment to reduce Hg emissions by an infinitesimal amount. The dichotomy is that the highest cost liquid fuel available that provides lowest PM and CO emissions cannot meet both HCl and Hg emission limits imposed by EPA. EPA should be obligated to explain how such a rule is justified and why this is not over-reaching. It would appear logical that a MACT standard could be developed which simply required use of "cleaner" fuel oil would be a viable and supportable approach that does not place affected sources in a losing position relative to the luck of the draw on oil quality.

C. The PM Limit in Boiler MACT for Oil Fired Units is Unachievable.

The liquid PM limits in the final Boiler Rule are set using a very small amount of data, and are not representative of fabric filter control technology (which EPA states is the technology assumed to be MACT for PM), as none of the floor units have controls. There are only 18 data points used to set the PM floor, one of which is labeled as detection level limited (DLL).

Considering this, the "top performers" are determined based on a very limited data set and reflect only combustion of distillate fuel oil or "anhydrides waste". In fact, no unit burning No. 6 fuel oil (even the one listed as having a fabric filter with sorbent injection) meets the liquid fuel PM limit based on the PM stack test and fuel firing information in the EPA database. EPA should reconsider its decision regarding further subcategorization of liquid units and should gather additional emissions information to ensure the final limits are achievable by boilers and process heaters burning liquids other than distillate oil or process liquids.

D. The CO Limit in Boiler MACT for Oil Fired Units is Unachievable.

EPA has grouped all boilers and process heaters firing any liquid fuel into one subcategory. Comments on the proposed rule suggested further subcategorization into heavy and light liquids. This further subcategorization was not incorporated into the final rule. In the response to comments, EPA states that although there are design differences between heavy and light liquid fired units, the approach taken in the final rule is consistent with that for solid fuels, as all solid fuels are grouped together for the fuel based HAP. EPA goes on to say that although solid fuel units are split for CO and dioxin/furan, they are not splitting light and heavy liquid units and the floors are made up of a mix of light and heavy units. Response to commenter EPA-HQ-OAR-2002-0058-1869.1, Comment Excerpt Number 4 (RTC, Vol.2, p.262).

The CO limits that EPA has finalized are made up of data that EPA has largely adjusted due to measurement capabilities of EPA Method 10, with little variability as a result. The floor units represent only 2 facilities (with 6 of the 7 floor units at a single facility- NJMerckRahway), with

one facility burning distillate fuel oil (NJMerckRahway) and one burning diesel fuel (SCGPChemRussellville).

The NJMerckRahway facility provided three No.2 Distillate Oil analyses; those reported sulfur levels of 0.03% (10/29/03), <0.05% (3/5/08), <0.05% (3/7/08). Thus these three analyses represented Distillate Oil with <500 ppm sulfur.

The SCGPChemRussellville facility noted in its Phase 1 ICR response that the FO Boiler fired ultra low sulfur diesel fuel. No sulfur analysis was provided for that oil, but it must meet the specification for that type oil, that being < 15ppm sulfur.

Therefore, the existing unit CO MACT floor emission limit is based only on use of ultralow sulfur diesel fuel and very low sulfur distillate oil. In fact, the No.2 Distillate Oil used at NJMerckRahway is 1/10 the sulfur level considered by EPA to be very low sulfur oil. The ICI Boiler NSPS (40CFR60.41b) defines very low sulfur oil as follows:

> Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO2 emission control, has a SO2 emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and not located in a noncontinental area, very low sulfur oil means oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO2 emission control, has a SO2 emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and located in a noncontinental area, very low sulfur oil means oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO2 emission control, has a SO2 emission rate equal to or less than 215 ng/J (0.50 lb/MMBtu) heat input.

Whereas EPA's past NSPS practice has been to allow use of fuel oil meeting a sulfur specification to meet SO2 emission standards; EPA's data demonstrates that units firing extremely low sulfur fuel oils are best performers for CO and PM; and EPA's primary benefit focus (highest claimed benefits) derive from SO2 emission reductions under the Boiler MACT rule, it follows that EPA should be at the very least establishing a compliance mechanism that would rely on firing of extremely low sulfur fuel oil with no other restrictions on emissions or required emissions controls. EPA would, however, need to address the other pollutants as identified herein, since the final liquid emission limits are demonstrated to be problematic for extremely low sulfur fuel oils.

CO Catalyst Impacts

EPA has failed to recognize the unachievable nature of their CO emission limits relative to control technology. The following data is all included within that provided to EPA under its ICR process. The seven top performers used to establish the CO existing unit floor include the following units at NJMerckRahway, with pertinent data provided for each unit:

Unit No.	Year Installed	Heat Input Capacity, MMBtu/hr	Emission Control and Year Installed	Reported & (EPA Assigned) CO Emissions, ppm	Emission Test Date (year)
B3	1997	99	SCR- Yr 1	1.7	2008
B5	1997	99	ULNB/FGR- Yr 1	1.3 (3)	2008
B9	1997	99	SCR- Yr 1	0.5 (3)	2008
B10	2000	249	SCR-Yr 1 CO/VOC Cat Ox- Yr 2	1.3 (6)	2003
B11	2004	249	SCR-Yr 1 CO/VOC Cat Ox- Yr 2	4.9	2008
B12	2000	249	SCR-Yr 1 CO/VOC Cat Ox- Yr 2	8.0	2008

Conclusions that can be drawn from this data:

- All emissions tests were conducted after all emissions controls had been installed on the units.
- On average, units equipped with oxidation catalysts for CO and VOC control exhibited higher CO emissions than the units not equipped with oxidation catalysts.
- Therefore, this head-to-head comparison of units firing the same fuel (very low sulfur distillate oil) demonstrates that installation of oxidation catalysts is not an effective control method for these boiler types and fuel. Thus, application of control technology cannot be assumed by EPA to be able to control CO emissions from any other units lacking data proving otherwise.
- Based on this information, EPA is obligated to reconsider the methodology and approach taken to developing the liquid CO MACT floor requirements.

III. FLOOR DETERMINATIONS – SOLID FUELS—HCl

EPA used inappropriate methods and data to establish the MACT Floor emission limits for new and existing units. These must be corrected in order to establish a floor which is not arbitrary and biased. Full reconsideration of all solid fuel based HAP emission limits is required.

EPA proposed emission limits for solid fuel fired sources in the proposed rule. In the proposal, EPA provided separate HCl and Hg emission limits for coal fired units and biomass fired units. Specifically, new coal fired units (all firing types) had emission limits of 0.00006 lb/MMBtu for HCl and 2.0E-6 lb/MMBtu for Hg; new biomass fired units (all firing types) had emission limits of 0.004 lb/MMBtu for HCl and 2.0E-7 lb/MMBtu for Hg. Existing coal fired units (all firing types) had emission limits of 0.02 lb/MMBtu for HCl and 3.0E-6 lb/MMBtu for Hg; existing biomass fired units (all firing types) had emission limits of 0.006 lb/MMBtu for HCl and 9.0E-7 lb/MMBtu for Hg.

Several groups submitted comments detailing the problems identified with the HCl and Hg floor setting process used by EPA for coal and biomass fired units. In the final Boiler Rule, EPA revised their subcategorization method and applied common PM, HCl, and Hg emission limits on all solid fuel fired units. Specifically, new solid fuel fired units must meet emission limits of 0.0022 lb/MMBtu for HCl and 3.5E-6 lb/MMBtu for Hg; existing solid fuel fired units must meet emission limits of 0.035 lb/MMBtu for HCl and 4.6E-6 lb/MMBtu for Hg.

Units identified as top performers are listed in the EPA Appendices. Specifically, the following are listed:

- mjrAppendix B, Sheet B-2b ranks INAlcoaWarrick Unit #3 as the top HCl performer with a minimum test average emission rate of 0.000015 lb/MMBtu.
- mjrAppendix B, Sheet B-2b ranks INAlcoaWarrick Unit #2 as 6th ranked top HCl performer with a minimum test average emission rate of 5091E-5 lb/MMBtu.
- mjrAppendix C, Sheet C-1b(i) provides individual emission test run data used to establish rankings and MACT floor limits. The data for INAlcoaWarrick Unit #3 is given below with a calculated average emission rate.

Data Source	Test Date	Test Run HCl Emission Value, lb/MMBtu
ICR Phase I	8/7/2008	0.0000143
ICR Phase I	8/7/2008	0.0000157
ICR Phase II - ERT	8/17/2009	0.000254326
ICR Phase II - ERT	8/17/2009	0.000234316
ICR Phase II - ERT	8/17/2009	0.000248123

Calculated Average = 0.000153

- mjrAppendix C, Sheet C-1b(i) provides individual emission test run data used to establish rankings and MACT floor limits. The data for INAlcoaWarrick Unit #2 is given below with a calculated average emission rate.

Data Source	Test Date	Test Run HCl Emission Value, lb/MMBtu
ICR Phase I	8/6/2008	0.0000151
ICR Phase I	8/6/2008	0.000103
	Average =	5.91E-05

- mjrAppendix A provides fuel analysis data. Notably, EPA does not list any fuel analysis data for INAlcoaWarrick.

The **proposed** rule Appendix C data used by EPA to establish the proposed MACT floor emission limits included only the Phase I data from 8/6/2008 testing for Unit #3 and the Phase I data from 8/7/2008 testing for Unit #2. It must be noted that the average of the two listed Unit #3 test runs is 0.000015 lb/MMBtu, as used in the proposed rule data set as the test average.

EPA appears to have reused the Phase I data they had used in the proposed rule, but added the Phase II HCl emission data for Unit #3 for the final rule analysis. As indicated in the Alcoa comments noted above, the Unit #3 emissions data originally listed in the proposed rule database (two runs dated 8/7/2008 from Phase I) were diagnostic data and not real test data upon which a rule can be based, and that data should have been dropped from the database. Valid emission test data including three test runs as indicated above in response to the ICR Phase II dated 8/17/2009 are the only legitimate HCl performance data for Unit #3 (note that all three emission rates were noted as BDL).

Similarly, EPA also reused the Phase I data listed as being for Unit #2, which Alcoa noted to be incorrect since no valid testing had been done on Unit #2. Therefore, that Unit #2 HCl emissions data dated 8/6/2008 should have also been deleted from the database.

Therefore, while EPA responded to the comments by saying they processed the corrections, all they apparently did was add the Phase II emission test data for Unit #3, but did not delete the incorrect data for Units #2 and #3 from the Phase I ICR collection.

EPA must delete the listed Phase I HCl emission data for both INAlcoaWarrick Units #2 and #3 from the database per notification from Alcoa. When this is done, Unit #2 is no longer in the dataset and drops out of the top performer list because there is no other HCl emission data for that unit. Also, dropping the two Phase I emission rates from the Unit #3 emissions data will change that unit's average emission rate and thereby change floor determinations. Thus the top performer selection process would need to be redone and all floor determinations and variability corrections re-determined.

Furthermore, EPA's data handling for INAlcoaWarrick Unit #3 is incorrect in any case, assuming for the moment that all five reported emission rates as noted above are correct. The average emission rate identified in Appendix B, Sheet B-2b for Unit #3 as noted above is 0.000015 lb/MMBtu. However, that actually is the average emission rate for the two Phase I emission rates that were used for the proposed rule. The actual correct average of those five emission rates (assuming they were valid as EPA did) is 0.000153 lb/MMBtu as indicated above as the "Calculated Average." Therefore, EPA erroneously used the wrong average for that unit in its listing of HCl top performers, and this resulted in erroneous floor determinations as well as erroneous selection of that unit as the top performer for use in determining the new unit MACT Floor. Just taking the calculated average HCl emission rate of 0.000153 lb/MMBtu, that would place Unit #3 as the 13th top performer, thus still within the top 12% of units, but not the top performer. This is a major error that likely resulted in a significant lowering of the final emission limits and demonstrates that there are probably other major problems with the rulemaking process that simply must be reconsidered and corrected.

EPA must rework its data handling procedure, correct errors, and re-determine the top performers and best performer and the resultant emission limits for both existing and new sources.

As indicated above, Appendix A includes no fuel data for the INAlcoaWarrick facility. There is no fuel data for that facility in any of the EPA supporting data. However, Alcoa specifically did submit fuel quality data to EPA, but that never found its way into the database and was thus never used by EPA. EPA used Unit #3 as the best performer for establishing the new unit MACT floor for HCl (obviously the result of the erroneous average emission rate listing noted above). EPA noted the lack of fuel quality data in the Revised MACT Floor Analysis document (p.18):

> For new solid fuel units, since the floor was based on the best single unit of the subcategory, we determined that a FVF was appropriate. The best performing solid unit for mercury is also the best performing coal unit. This unit has additional test data burning 25% coal and 75% biomass, which is included in the UPL calculations for this subcategory. Given the variability of coal fired from this best performing unit, a FVF was multiplied by the new source solid fuel UPL for mercury. For HCl, there is no available FVF from the best performing unit so no FVF was applied.

If EPA had appropriately included the data submission from Alcoa in the database, it would have been able to include that fuel quality variability within its analysis for both existing units and new units. The Excel file submitted by Alcoa is attached. There are issues that should be noted relative to that fuel quality data:

- EPA Appendix C, Sheet C-1b(ii) lists the fuel for the INAlcoaWarrick units as Coal/Bituminous, whereas the FuelAnalysisTemplatealcoawarrick spreadsheet identifies the fuel as Sub-bituminous. Again, this is indicative of errors in the EPA data and analysis.

- The 12 coal sample analyses provided for that facility indicate fairly high chlorine content variability (40 to 200 ppm), but also a very low coal chlorine content. Both the low chlorine content of sub-bituminous coal and the high variability are critical features of the fuel used by the unit which EPA had selected as the best performer for establishing the new unit HCl emission limit and included within the best performer list for the existing unit limit. Thus, omitting use of the fuel quality data is yet another major error on the part of EPA that results in a lower emission limit and a bias against regulated entities.

The approach taken by EPA to simply ignore fuel quality variability for fuel-based HAP such as HCl is inexcusable and results in an inherent bias against various unit designs, fuel types, and regulated entities to the point of presenting an intended bias. EPA explained its approach as noted above. But the fact that EPA did not see anything wrong with not applying some type of fuel variability factor to the new unit HCl emission limit is troubling at best. In the first instance, EPA was presenting the best performing unit as a bituminous coal fired unit, whereas it is actually a sub-bituminous coal fired unit. Second, EPA was using incorrect data for that unit. And third, EPA was not applying fuel variability to that determined emission rate, even though fuel quality data had been provided to EPA. The Alcoa coal equivalent HCl emission rate is 0.012 lb/MMBtu. This can be compared to >3000 EPA listed bituminous coal analyses that indicate an average equivalent HCl of approximately 0.06 lb/MMBtu (excluding obvious erroneously high reported values). Therefore, EPA's final rule methodology of establishing a new unit MACT floor HCl emission rate on the basis of one unit firing inherently low chlorine sub-bituminous coal without somehow considering the overall variability of all fuel types to be regulated under that limit is wholly inappropriate. This is even more apparent when it is considered that EPA imposed that limit on all solid fuels.

EPA must ensure that provided data is utilized in evaluating emissions performance and determining MACT floors. EPA must ensure that data used for establishing the emission limits is accurate and used properly. In addition, EPA must account for inherent fuel variability when evaluating HAP emissions that are highly dependent on fuel content, such as Hg and HCl. EPA cannot base an entire subcategory emission limit on characteristics of a single fuel when several different fuels are included within that subcategory without properly considering the inherent variability among all of those fuels; EPA has plenty of data on which to consider fuel variability across the US. If that cannot be done, then additional subcategorization must be done to avoid establishment of arbitrary and capricious standards.

IV. THE 02 CEMS REQUIREMENTS NEED TO BE REVISED.

This final rule includes O2 CEM and related issues that were not included in the proposed rule, denying sources the opportunity of a notice and comment period. In principle, O2 CEMs can be helpful for sources, however, the caveats presented in this final rule make it unworkable in some cases and additional flexibility is required.

First, the location of the measurement device is problematic for some units. Section 63.7525(a) of the final rules states, "[t]he oxygen level shall be monitored at the outlet of the boiler or

process heater," preventing sources from being able to use existing O2 trim analyzers which imposes needless additional costs. 76 Fed. Reg 15,671. EPA should allow the option of using existing O2 analyzers which are mounted in optimum locations. Requiring stack gas to not be "below the lowest hourly average" in many cases eliminates the ability to use existing trim sensors which are located at the boiler outlet, upstream of air heaters to sense closer to furnace conditions. 76 Fed. Reg 15693. This requirement also ignores potential impacts of regenerative air heater leakage changes which impact apparent O2 levels downstream, but not furnace conditions which would be of interest relative to CO formation . EPA should allow for existing O2 analyzers which are mounted in optimum locations for O2 trim control. PS-3 and stack location should not be required and sources should be allowed to optimally locate the device. EPA needs to reconsider this issue as it is a new requirement. There are some units where locating O2 sensors in the breeching or stack is appropriate, so options should be provided to allow optimum monitoring.

Second, EPA should allow the use of CO CEMS as an alternative on a 30-day rolling average basis. Many facilities in Texas are required to measure both CO and O2 in stacks. Since regulation requires the use of an O2 CEMS, sources with CO CEMS will be faced with multiple requirements given the fact that CO CEMS provide valid results and could demonstrate compliance with O2 but not the CO limit on a continuous instantaneous basis. This needs to be addressed either by (1) allowance of use of either CO CEMS or O2 CEMS, or (2) alternate monitoring method whereby the site is allowed to demonstrate continuous compliance with CO CEMS. If existing CO CEMS is installed and no 30 day rolling average is stipulated in the rule, there is a credible evidence problem given it might be interpreted to apply on an instantaneous basis which is completely unreasonable. It is irrational to ask a boiler with dilution-extraction CEMS system (which uses CO2 as a diluent and cannot measure O2) to install completely redundant full-extraction CEMS solely for the purpose of measuring O2 (or CO, for that matter). EPA should give alternative CO lb/mmbtu standards so existing dilution-extraction CEMS can be utilized with relatively inexpensive additions of CO monitors.

V. START-UP, SHUTDOWN, MALFUNCTION

A. Start-up/Shutdown

Following the work practice of manufacturer's instructions, start-up/shutdown appears to be excluded. However, § 63.7535(c) requires all periods of data except malfunctions, out-of-control periods, etc. to be used in calculating averages. While this seems to be an error, Start-up/Shutdown needs to be added through a technical correction.

B. Malfunction Affirmative Defense

Malfunctions are in all material respects the same as startup and shutdown and therefore should have work practice standards as well. EPA recognized, regarding startup/shutdown "that it is not feasible to require stack testing—in particular, to complete the multiple required test runs—during periods of startup and shutdown due to physical limitations and the short duration of startup and shutdown periods. Operating in startup and shutdown mode for sufficient time to conduct the required test runs could result in higher emissions than would otherwise occur."

There is no rational basis for coming to any different conclusion for periods of malfunction. In fact, the argument for malfunction is even stronger, as if is the case sometimes, a malfunction jeopardizes personnel safety and could cause permanent equipment damage, running testing equipment during those periods is not an option. EPA should establish a "work practice standard" that requires pre-determined malfunction plans with practices and procedures for potential malfunctions; require reporting of any malfunctions; address any malfunctions not contemplated and add to the plan and address as appropriate.

The malfunction defense EPA provides in the final rule includes ill-defined terms and criteria that are not necessarily indicia of the occurrence of a malfunction. The defense therefore lack the objectivity that is fundamental to proving the applicability of the provision. For example, the requirement that sources rely on overtime workers to address the malfunction, objectively proves nothing. The personnel onsite at the time of the malfunction event may not be the personnel with the expertise to resolve the malfunction, yet if they do not remain onsite as overtime personnel, under EPA's structure, that source fails to meet one of the indicia of a malfunction. EPA's approach irrationally subjects sources to the risk of noncompliance for malfunctions that are an unavoidable, objectively defined standard plant occurrence but that will not be provable as such due to EPA's subjective criteria. Especially because noncompliance is the penalty a source suffers for failing to meet the criteria, the rule is not reasonable. EPA should grant reconsideration and take notice and comment on this issue.

VI. HEALTH-BASED EMISSION LIMIT

In the proposed rule, EPA requested comments on the possibility of establishing health-based emission limits (HBEL) for HCl and other acid gases. 75 Fed. Reg. 32,031. Throughout this process, EPA has received a significant amount of facility-specific emissions data related to coal analysis and variations from all sources. Section 112(d)(4) does not require that EPA limit its analysis to only the top performing sources used to set the MACT floor; therefore, EPA should have considered all of the source data it has received in its effort to look at the variability of acid gas emission rates. However, despite the availability of this data, in the final rule EPA decided not to exercise its authority under section 112(d)(4) and adopt health-based emission limits (HBEL) for HCl and other acid gases.

EPA attempts to justify its decision by citing the variation of acid gas emission rates as a "significant data gap," incorrectly stating that "[a]dditional data were not provided" and that the data EPA already possessed was "not sufficient" to justify emissions standards that take into account the health threshold for acid gases. 76 Fed. Reg 15642-43. EPA's failure to consider the quality data provided by commenters demonstrates that the Agency has not adequately considered and addressed the issue of establishing a HBEL. This information indicates quality variability and EPA should consider this data when evaluating whether a HBEL is appropriate.

VII. TOTAL SELECTED METALS

Inclusion of a total selected metals (TSM) option into the Boiler MACT rule will provide greater compliance flexibility for sources while still protecting the environment from the emissions of non-mercury HAP metals. The TSM option would offer the opportunity for sources to achieve

low metal HAP emissions similar to those achieved with the use of PM as a surrogate for HAP metals, but potentially at a lower cost.

CIBO continues to support the Agency's use of PM as a surrogate for HAP metals. PM is a reasonable surrogate for the non-mercury metallic HAPs even if the ratio of metals to PM is small and variable, or simply unknown. As noted by EPA in the preamble to the proposed rule, "[m]ost, if not all non-mercury metallic HAP emitted from combustion sources will appear on the flue gas fly-ash." 75 Fed. Reg. 32,018. Therefore, control technology installed to capture PM will also capture these non-mercury metallic HAP along with other particulates.

CIBO understands EPA's approach to use particulate matter as a surrogate for non-mercury metallic HAP since metals are a component of particulate matter and testing for PM is simpler than testing for total metals. However, to enhance compliance flexibility options in the final Boiler MACT rule, EPA should also include a total selected metals (TSM) emission limitation option as an alternative to the particulate matter emission limit. TSM would be defined to include the sum of the 10 non-mercury HAP metals identified in the Clean Air Act HAP list: antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium. Inclusion of a TSM emission limitation as an alternative to the particulate matter emission limit is appropriate since the emissions of these non-mercury metals are the hazardous air pollutants the standard is intended to regulate.

In the Boiler MACT rule, TSM would be defined as the sum of the 10 non-mercury HAP metals. It would not be practical or necessary for EPA to set emission limits for each of these individual metals due to the fact that so many of them are present below detectable levels. The use of a TSM alternative is therefore appropriate, and TSM emissions standard can be determined using available metals emission data in EPA's database. Summing the data and using a total makes more sense since non-detects will be present. EPA will need to include instructions in the final rule on how to treat non-detects since there is no guidance in EPA Method 29. A scientifically defensible method for addressing the handling of non-detect test results is needed and this methodology will need to ensure test results which are below measurable levels (e.g. non-detects) will not put sources in a situation of being non-compliant with the standard.

The framework already exists in the final rule to ensure that sufficient monitoring is performed for a TSM alternative standard. The rule, at §63.7530(b), contains procedures for determining initial compliance with mercury and hydrogen chloride through stack testing and fuel analysis. This approach could be easily adapted for a TSM standard as well. Section 63.7540 of the rule also contains procedures for determining continuous compliance with mercury and hydrogen chloride and could be adapted to TSM. If a source selects the TSM alternative, there would not be the need to continuous monitor PM emissions. While the TSM alternative may require increased costs for stack testing and fuel analysis, the costs associated with the initial installation and on-going maintenance and manpower support for a PM continuous monitor will not be incurred

In order to provide additional compliance flexibility for sources that combust biomass, EPA can utilize the approach contained in the 2004 Boiler MACT rule TSM compliance alternative option. The combustion of wood fuels may result in higher emission of manganese than

combustion of fossil fuels. Increased use of renewable fuels such as woody biomass is part of our national energy and climate policy. In this approach for biomass combusting sources, manganese emissions would not be included in the TSM calculation but facility emissions of manganese would be assessed to either a look-up table value or through site specific modeling to not exceed an appropriate and specified value. Providing this alternative TSM compliance strategy will provide a compliance mechanism that will not disadvantage the use of wood fuel.

VIII. FUEL SWITCHING

Over the past three years, EPA has undertaken numerous regulatory initiatives that as an aggregate make fuel switching a likely compliance option for many sources. EPA's greenhouse gas regulations, including the Tailoring Rule, and the recently finalized SO2 and NO2 NAAQS combined with the unduly strict standards EPA included in the final Boiler MACT will create an environment where it will no longer be feasible for some sources to burn coal or oil fuels. These sources will therefore be forced to switch to cleaner fuels, such as natural gas as a means of managing economical and technical compliance issues. While EPA recognized in the proposed rule the challenges associated with standards that forces fuel switching, the agency failed to consider such challenges adequately.

Even if a source determined that fuel switching is the only means by which it can continue to operate, the short compliance timeline in the final rule makes it more likely that sources will have to shutdown until they can demonstrate compliance. This is due to issues that were even recognized by EPA in the proposed rule, including infrastructure issues as well as natural gas supply availability issues. Specifically, fuel switching to natural gas requires a multitude of different interim milestones, including permitting, securing pipeline easements, pipeline construction, and construction of new boilers to accommodate the new fuel. These steps will take several years. EPA has not considered the timeline to complete all steps when determining compliance and many facilities may be faced with shutting down until they can demonstrate compliance with the final Boiler MACT. A source that plans to switch to a cleaner fuel but does not wish to shut down would be forced to install emissions controls on its existing boiler to comply with the three year compliance deadline.

Through reconsideration of this rule, EPA could establish an iterative compliance process for those sources that are forced to switch to cleaner fuels. Specifically, EPA should provide sources that are switching to cleaner fuels a period of six years to install new boilers. Such an approach would provide an added incentive for sources to switch to cleaner fuels.

Additionally, if a source were to switch from natural gas to solid fuel, EPA has made it so these units would be considered new sources and subject to new source emissions. As such, existing sources that have gas burners, if burning biomass, want to switch are unable to switch back because they would be considered new source boilers.

IX. ENERGY ASSESSMENT

A. The Energy Assessments Are Not an "Emission Standard" or Means of HAP Control.

EPA proposed what it refers to as a beyond-the-floor standard that would apply to all existing major source facilities and require "the performance of a one-time energy assessment" for the purpose of identifying cost-effective energy conservation measures. 75 Fed. Reg. 32,058 (proposed 40 C.F.R. § 65.7530). EPA inaccurately asserted in its proposal that the energy assessment alone would lead to emission reductions. 75 Fed. Reg. 32,026. Commenters noted that there is no legal basis for EPA to include an energy assessment as a beyond-the-floor standard, citing the fact that an energy assessment is not an "emission standard" under §112(c)(2). 42 U.S.C. § 7412(c)(2). In response to these comments, EPA states that "the requirement to perform the energy audit is, of course, a requirement that can be enforced and thus a standard." 76 Fed. Reg. 15,633. Despite EPA's statement that an energy assessment is a standard that can be enforced, the agency failed to consider that the mere identification of potential energy conservation measures does not equate to an "emission standard" resulting in emission reductions.

An energy assessment does not purport to limit emissions, nor impose more stringent standards than the MACT floor and is therefore not a beyond-the-floor standard consistent with the text of the Clean Air Act. Furthermore, even if efficiency measures identified in the energy assessment are actually implemented, the reduced demand for the output of a regulated source is not an "emission control" technology to limit emissions from the regulated source. §112(c)(2); 42 U.S.C. § 7412(d)(3).

B. The Scope of the Energy Assessment is Beyond EPA's Authority.

Commenters also stated that EPA lacks the authority to impose requirements on portions of the source beyond the specified emission unit, i.e. the boiler or process heater. In response to these comments, EPA offers the following statement:

> [W]e have carefully limited the requirement to perform an energy audit to specific portions of the source that directly affect emissions from the affected source. The emissions that are being controlled come from the affected source. The process changes resulting from a change in an energy using system will reduce the volume of emissions at the affected source by reducing fuel consumption and the HAP released through combustion of fuel. 76 Fed. Reg. 15,632.

By its own terms, the rule covers "affected sources" – defined as all existing and new ICI boilers and process heaters located at major sources. The "affected source" regulated by this NESHAP is the specified emission unit – boilers and process heaters – not the major source location of the emission unit. This is consistent with the long-established understanding of the term "affected source" as it relates to the "major source" where the affected source is located. *See* preamble to

rule establishing the General Provisions for all NESHAPs, 59 Fed. Reg 12,408, 12,412-13 (March 16, 1994).

EPA's proposal extends well beyond reduction of emissions by "sources" and seeks to compel regulated entities to investigate, monitor and report activity at units unregulated by the Clean Air Act. This approach is arbitrary and capricious as EPA must limit regulatory requirements to methods that will reduce HAP emissions by the regulated combustion unit itself and not to other systems, energy using systems or process areas. EPA goes beyond its authority by imposing requirements beyond the combustion unit, even covering systems not directly associated with combustion units.

EPA's authority is limited to setting emission limits for the affected combustion unit and does not extend to components not immediately associated with the combustion unit, nor to the energy using process areas. What EPA requires goes far beyond its authority. EPA should reconsider limiting the scope of the energy assessment to "those portions of the facility using the energy generated from the affected boiler system" as it is done in the final Area Source rule. 76 Fed. Reg. 15,573.

C. The Definition of Energy Assessment and Energy Use System is Too Broad.

In the final rule, EPA provides that an energy assessment must be conducted on the "boiler system and any energy use system accounting for at least 20 percent of the energy output." 76 Fed. Reg. 15,683. The term "energy use system" is a new definition that was not included in the proposed rule and therefore EPA has provided no opportunity for comment. The definition of "Energy use system," includes, but is not limited to, "process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air conditioning systems; hot heater systems; building envelope; and lighting." 76 Fed. Reg. 15,683.

The energy use described in the definition for "energy use system" includes in many cases activities associated with the use of electricity. However, where this electricity is purchased from others, it has no impact on the combustion unit fuel use or associated emissions, and thus is outside the intended scope of the energy assessment. EPA should clarify that those energy uses that are not associated with combustion sources on the site are excluded from this definition. EPA appears to acknowledge the reasonableness of such an approach in the definition of "energy assessment" included in the final Area Source rule. Specifically, in the final Area Source rule, EPA specifies that only energy use systems associated with the "affected boiler(s) energy output" should be evaluated in the energy assessment. 76 Fed. Reg. 15,600. EPA should include similar language in the "energy assessment" definition for this final rule.

The definition of "energy assessment" in the final rule includes a stated maximum time for conducting an energy assessment of a one (1) day maximum for < 0.3 trillion Btu/yr heat input and three (3) days maximum for 0.3 to 1 trillion Btu/yr heat input. 76 Fed. Reg. 15,683. These maximum times for conducting an energy assessment were not included in the proposed rule.

The maximum times aspect of the definition is unclear as the phrasing could imply a deviation and potential violation if the energy assessment exceeds those time limits. EPA should modify

the definition of "energy assessment" to clarify that while these times are expected maximum times for conducting the assessments, actual times can exceed the indicated times depending on site specific conditions. This will ensure that deviations or enforcement is not applicable to the elapsed times.

In the final rule, EPA expanded the energy assessment requirement to include "[a] comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments." 76 Fed. Reg. 15,692. This is a new requirement not included in the proposed rule and will require significant time and effort to accomplish. It is not clear that such an undertaking is possible in light of the maximum times outlined in the energy assessment definition of the final rule. 76 Fed. Reg. 15,683. Furthermore, it is not clear that EPA considered the costs associated with this requirement.

D. The Premise that Energy Assessments Will Reduce HAP Emissions is Grossly Over-Simplified and Inaccurate at Complex Facilities.

EPA justifies requiring sources to conduct an Energy Assessments by claiming that "[t]he process changes resulting from a change in an energy using system will reduce the volume of emissions at the affected source by reducing fuel consumption and the HAP released through combustion of fuel." 76 Fed. Reg. 15,632. This reveals a serious flaw in EPA's understanding of how large, integrated manufacturing facilities actually operate. From a strictly academic point of view, an industrial boiler system serving a process could be represented as three simple and discrete parts:

(1) A boiler or process heater, which combusts fuel(s) to generate electricity and/or steam. Emissions of criteria pollutants and HAPs result from, and are proportional to, the quantity of fuel combusted. The quantity of fuel combusted is dictated by process demand (i.e. how much electricity and/or steam the process requires), unavoidable losses (e.g. stack losses, etc.), and avoidable losses (e.g. degradation in air preheater performance, insulation failures, etc.).

(2) The process, which requires some amount of electricity and/or thermal energy to manufacture its product(s).

(3) Distribution infrastructure, which delivers the electricity and/or thermal energy from the boiler to the process, returns condensate or heat transfer fluids back to the boiler, and supplies makeup supplies (e.g. boiler feedwater, fuel, etc.).

For industrial or commercial facilities that are similar to this model (e.g. a single boiler serving a single thermal demand), it is generally accurate that a reduction in energy demand from the process would have a corresponding reduction in fuel consumption, and thus a reduction in HAPs emitted. Whether or not the facility would judge the cost to implement a process change that would reduce the consumption of energy as a good investment is an open question, and dependent upon a variety of site-specific, company-specific, and industry-specific factors.

However, at large integrated manufacturing facilities (e.g. refineries, integrated chemical manufacturing facilities, etc.), this simplistic academic view of how energy-using processes and fuel-consuming boilers and process heaters are integrated is inadequate. Many large integrated manufacturing facilities possess a variety of manufacturing steps, each of which has its own characteristic energy intensity level (e.g. Btu per pound of product) and thermal demands (e.g. Btu per hour, specific temperature requirements, etc). To satisfy a variety of process demands, each with its own specific temperature regime and mass flow requirement of steam and/or heat transfer fluids, it would be absurdly inefficient to install a fleet of boilers wherein each boiler were designed to satisfy a specific manufacturing unit's thermal requirements (e.g. one boiler provides steam at 100 psig; another boiler provides steam at 200 psig; a third boiler provides steam at 600 psig). Instead, plants are designed with boiler(s) that typically generate steam at one specific set of conditions that may not be aligned with some of the manufacturing process thermal demands. The plant would be designed to generate steam at a high temperature and pressure to satisfy one specific process demand; that process step would then exhaust a lower-energy steam or condensate back into the plant, to be used by a lower-temperature thermal process user. That process step would then exhaust the yet-again lower-energy steam or condensate back into the plant to be used by a yet-lower temperature thermal process user, ad infinitum, until all useful energy had been extracted from the steam. At that point, condensate would be returned to the boiler to be re-boiled and re-introduced into the plant.

For example, consider Eastman Chemical Company's integrated chemical manufacturing site in Kingsport, Tennessee. Eastman operates a fleet of 17 boilers plus a variety of smaller process heaters to cogenerate electricity and meet thermal demands at the plant. Most steam is generated by the boilers at 1450 psig, drives turbine-generators to generate electricity, and is exhausted into the plant at 600 psig. Other boilers generate steam at 600 psig directly. The steam demand of the plant is divided into three general thermal regimes: 25% at 600 psig, 55% at 100 psig, and 20% at 15 psig (nominally). Steam is "moved" from higher pressure to lower pressure by using steam turbines or thermal condensing loads and flash tanks, meaning that one pound of high-pressure steam is used at multiple pressures (e.g. 1500 psig to 600 psig to 100 psig to 15 psig to condensate) before being returned to a boiler to be re-boiled into steam.

For a complex site such as Eastman's Kingsport plant, a hypothetical energy assessment could reveal process changes that would reduce the plant's demand for 100 psig steam. If such process changes were considered financially viable (i.e. the risk-adjusted internal rate of return for this energy efficiency project was higher than the rate of return for all competing projects being funded by the product line), consumption of 100 psig steam would be reduced. However, without corresponding and *simultaneous* reduction of steam demand at 600 psig and 15 psig steam, Eastman's boilers would still have to generate just as many pounds of steam in order to satisfy the thermal demands at 600 and 15 psig. In other words, just as much steam would be required to satisfy the thermal demands at 600 and 15 psig, despite the fact that fewer pounds of steam would be required at 100 psig. In such a scenario, the now-unneeded 100 psig steam would either be used in a condensing steam turbine (e.g. to generate electricity) or vented to the atmosphere. But significantly, the same number of pounds of steam would be generated. Thus, a significant reduction of 100 psig steam in the absence of reductions at 15 psig and 600 psig

would result in *no change* to the amount of fuel combusted to satisfy the plant thermal demand, and *no change* to the HAP emissions.

In fact, this condition sometimes exists at Eastman's Kingsport plant: The imbalance between thermal demands in the various steam headers results in the venting of steam under certain operating conditions. Eastman's Kingsport plant is not unique: Many large, integrated facilities use steam at multiple pressures and temperatures to satisfy varying thermal demands, and utilize steam turbines and/or condensing loads with flash tanks and/or pressure-reducing valves to move steam from one pressure level to another. A common feature at large integrated plants is that one pound of steam typically sees "duty" at many or all pressure levels before being returned to the boiler for re-boiling. It takes reductions at *each* pressure level *simultaneously* to reduce the amount of fuel that is combusted in the boiler. Therefore, the assumption that any single energy conserving measure will directly and automatically reduce the consumption of fuel, with attendant reductions in HAP emissions, is grossly oversimplified and inaccurate at larger integrated sites. It requires comprehensive, integrated, site-specific understanding of the boilers and process heaters, as well as the specific manufacturing processes at a large integrated plant, in order to reduce the amount of fuel consumed. So while energy efficiency in aggregate is a powerful tool to reduce the consumption of fuel, EPA's presumption that using the CAA to mandate energy assessments of manufacturing processes, in whole or in part, will yield reductions in HAP emissions at all affected sources is demonstrably false.

EPA should instead limit the scope of its energy assessments to the Boiler or Process Heater and its direct auxiliary systems (e.g. feedwater pumps, feedwater heaters, air preheaters, combustion systems, boiler insulation, blowdown, sootblowing controls, etc.). When the energy efficiency of the Boiler and its direct auxiliary systems is improved, a direct and immediate reduction in fuel consumption will result, with predictable and reliable reductions in HAP emissions. And unlike the construct proposed by EPA, such improvements in energy efficiency would be *completely independent* of the process. In other words, improving the energy efficiency of the boiler will reap both economic and environmental improvements in every case, regardless of business cycle, product mix, steam balance, time of year, etc. By unnecessarily attempting to regulate the entire manufacturing complex, EPA has essentially guaranteed that its energy assessment will yield little practical benefit to the environment or human health at complex sites, while imposing an unnecessary cost burden on the owner/operator.

E. EPA Failed to Consider Various Energy Use System Configurations

There are cases where boilers or process heaters supply energy to third parties for their use. In those cases, the boiler or process heater owner/operator has no control over how the energy is utilized by those third parties. EPA needs to clarify that the energy assessment scope must only extend to facilities and equipment associated with affected units directly under the control of the affected unit owner/operator, and not extend further into any facilities or equipment not under their control.

F. EPA Failed To Consider the Costs of Implementing Energy Conservation Measures.

Section 112(d) requires that, in setting a beyond-the-floor standard, EPA consider the cost of achieving the emission reduction. 42 U.S.C. § 7412(d)(2). In its proposal, EPA estimates that the requirement for a one time energy assessment ranges from $2,500 to $55,000. 75 Fed. Reg. 32,026. However, while EPA attempts to justify energy assessments as a beyond-the-floor standard based on the premise that such assessments will result in the implementation of "energy conservation measures," EPA's only reference to the cost associated with implementing such "energy conservation measures" is that "the costs of any energy conservation improvement will be offset by the cost savings in lower fuel costs." 75 Fed. Reg. 32,026. EPA failed to consider the costs of actually implementing any "energy conservation measures" identified in the energy assessment.

X. TREATMENT OF PROCESS GAS STREAMS DIRECTED TO BOILERS BY ANOTHER MACT

CIBO supports EPA's decision that units should be exempt and not subjected to the boiler standards when the units are regulated by another MACT. 76 Fed. Reg 15,610-665. However, EPA did not allow for notice and comment on a provision that sets a 50 percent heat input requirement to exempt from Boiler MACT "any unit that is used as a control device to comply with another MACT standard, provided that at least 50 percent of the heat input is provided by the gas stream that is regulated under another MACT standard." 76 Fed. Reg 15,665. This requirement supports “one MACT” regulation of a combustion unit but fails to appropriately address process gas streams from an other-MACT regulated process unit that is directed to a gas-fired boiler or process heater subject to Boiler MACT.

Under the circumstance when another MACT directs a process gas stream to a gas boiler or process heater for control, an alternative approach could be that the stream required to be controlled per another MACT standard should not be required to meet fuel specifications to become a Gas 1 stream under Boiler MACT. In most cases these streams are a very minute heat input and likewise contribute a minute addition of any pollutants to the boiler or process heater relative to the fuel-derived emissions. As introduced in the final rule, this appears to be a duplicative control requirement.

XI. LIMITED-USE UNITS.

A. EPA Should Base the Limited-Use Definition on a 10 % Annual Capacity Factor.

In the Proposed rule, EPA did not include provisions for limited use units, and did not provide a definition of limited use units. However, in the final Boiler Rule EPA has created a limited use subcategory with a definition based on an operational period of 876 hours per year rather than an annual capacity factor with no sufficient explanation as to why. 76 Fed. Reg 15684. Sources were not given notice and comment opportunity on this specific issue; therefore, EPA should address the issues discussed below during administrative reconsideration.

While CIBO supports a limited use subcategory, it is more beneficial to base the definition on a 10% annual capacity factor rather than an arbitrary amount of hours such as 876. EPA recognizes the "unpredictable operation of this class of units" and that "they operate for

unpredictable periods of time, limited hours, and at less than full load," and as such, should have a more effective definition to ensure that sources are covered under the work practice standards of limited use and not face emissions testing. 76 Fed. Reg 15364.

In the response to comments, EPA notes that the limited use subcategory was created in order to "represent a specific type of boiler, those used as backup, emergency, or peaking units that operate infrequently." Vol. 2, BMACT RTC, EPA-HQ-OAR-2002-0058-2881.1 Excerpt 2. It is arbitrary and capricious to set a specific number of hours lower than what most limited use sources tend to run. By doing so, EPA will force many sources which should be considered limited use out of the subcategory. EPA should keep the 2004 vacated Boiler MACT definition which incorporates the capacity utilizations less than or equal to 10 percent. 69 Fed. Reg 55223.

Upon reconsideration, EPA should revise the limited use boiler or process heater definition to read as follows, leveraging from its use in 40 CFR Parts 72 and 75:

> *Limited-use boiler or process heater* means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable ~~**limit of no more than 876 hours per year of operation**~~ **average capacity factor of (i) no more than 10.0 percent during the previous three calendar years and (ii) a capacity factor of no more than 20.0 percent in each of those calendar years.**

In addition, EPA should incorporate the definition of capacity factor as follows, leveraging from its use in 40 CFR Parts 72 and 75:

> *Capacity factor* means the ratio of a unit's annual heat input (in million British thermal units or equivalent units of measure) to the unit's maximum rated hourly heat input rate (in million British thermal units per hour or equivalent units of measure) times 8,760 hours.

The approach taken by EPA in the final rule as indicated above addresses "units designed to burn gas 1" separately from limited use boilers or process heaters. The only material regulatory compliance difference for units only firing gas 1 is that the required tune-up frequency extends from 1 year for non-limited use gas 1 units to 2 years for limited use gas 1 units. That being the case, it is logical for EPA to simply apply the limited use criteria to liquid firing that occurs in a predominantly gas 1 fired boiler or process heater. If this approach was taken, units which fire liquids for less than the defined limited use quantity either alternatively or simultaneously with gas 1 would be afforded similar treatment with units only firing those same liquid fuels relative to compliance with liquid emission limits. Since those gas 1/liquid limited use combination units would be operated with gas 1 more than the limited use limitation, the tune-up frequency for those units should remain on an annual basis. Finally, EPA should add a provision that states that the limited use capacity factor limitation also applies to liquid fuels fired in a predominantly gas 1 fired boiler or process heater, but that the tune-up frequency for such units is on an annual basis.

B. EPA Unreasonably Failed To Include A Work Practice Standard for Limited-Use Units.

The definition of the limited use subcategory in the final Boiler Rule restricts the designation of "limited use" to a boiler or process heater that accepts a federally enforceable limit on the hours of operation to no more than 876 hours per year. CIBO supports the application of work practice standards to the limited use subcategory and believes application of work practice standards to boilers and process heaters in the limited use subcategory are appropriate and provide sufficient control to protect human health and the environment. CIBO requests that the EPA allow the application of the limited use subcategory to certain dual-fuel fired boilers as described below.

Many facilities operate boilers that use pipeline quality natural gas as the primary fuel, but which have the capability to fire distillate fuel oil (#2 fuel oil) as a back-up fuel. The preservation of the back-up fuel is necessary for many sources not only during periods of natural gas supply curtailment or during a loss of the natural gas supply as a result of other emergency conditions, but also for use during malfunction or maintenance on "plant-side" natural gas piping, metering, and valves. The cost of distillate fuel oil (per million BTU) compared to natural gas is high; few facilities with the flexibility will choose to use distillate fuel more than necessary given the budget impacts.

Some CIBO members are considering converting oil-fired boilers to dual fuel (natural gas and distillate oil) in order to provide more flexibility. The final Boiler Rule applies work practice standards to natural gas-fired boilers, but limits the use of fuel oil combustion on dual-fuel fired (natural gas and liquid fuel) boilers to emergency situations narrowly defined in the final rule. These narrowly defined emergency situations seem to exclude the use of fuel oil during malfunctions or maintenance of plant-side natural gas piping, metering, and valves, which would seem to then mean that dual-fuel fired boilers would have to comply with the Table 1 or Table 2 emission limits that apply to liquid fuels. This represents a very expensive option for sources that have the willingness and ability to accept a federally enforceable limit on hours of operation for the liquid fuels.

Because the definition of the limited use subcategory restricts the hours of operation to a boiler or process heater, CIBO requests that EPA amend the definition of "limited use" during the administrative reconsideration process to capture restriction of the hours of operation or capacity factor on a secondary fuel for natural gas fired boilers and process heaters. Such an approach is consistent with the EPA's evaluation of both the natural gas and limited use subcategories, as it continues to provide application of work practice standards to a boiler or process heater, minimizing the potential risks to human health or the environment.

XII. NATURAL GAS CURTAILMENT

The overall construct of the final rule definition of *"Period of natural gas curtailment or supply interruption"* presents problems that could be resolved through technical clarification or through further rulemaking action.

NG curtailment is defined in the MACT:

> *Period of natural gas curtailment or supply interruption* means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption. 76 Fed. Reg 15,685.

This definition is apparently written to protect those firms whose supply is downstream of a Local Distribution Company (LDC). Users downstream of a LDC can indeed have their supply halted when the needs of users exceed the LDC's available supply. In such a scenario, residential users (& hospitals, etc) would be given priority and an industrial firm would be shut off. This definition is a good and constructive thing for such users.

However, the current definition does not address the range of gas supply arrangements and would likely create confusion and eliminate routine cost-effective use of gas purchase contract arrangements. Such impacts would extend beyond EPA authority and delve into state and FERC regulatory authority. The range of gas supply arrangements can include purchase from aLDC under state jurisdiction or interstate gas purchase under FERC jurisdiction. Purchased transportation can be firm (a consumer contracts for a specific amount of transport capacity) or interruptible (a consumer can be interrupted by the transporting entity at the transporting entity's will), or a combination of firm and interruptible. Because a site must pay a cost for firm transportation whether the gas is actually purchased or not, many large natural gas consumers utilize contracts that incorporate a combination of firm and interruptible supply contracts to optimize transportation costs in light of variation in natural gas demand.

Normally, with purchase of firm transportation, the risk of curtailment limits a firm's delivery amount to the firm transport capacity purchased (or the firm's daily nomination, whichever is less). Curtailment typically occurs when demand is unusually high, e.g., with very cold weather. Firm transport customers are normally only subject to curtailment to less than their firm capacity when the transporter suffers a force majeure situation (e.g., a compressor station failure, pipe failure), or the supply is significantly disrupted (e.g. a major hurricane in the Gulf of Mexico).

In the case of interstate gas contracts, there are provisions that would hypothetically allow a consumer to buy natural gas in excess of their contractual firm transportation amount during a curtailment. However, penalties in tariff agreements, regulated by FERC, are draconian and intended to make the a violation of curtailment so painful as to effectively prohibit a consumer from attempting to defy the curtailment order (e.g. one interstate pipeline tariff cites a $15 per dekatherm penalty on top of Henry Hub prices, effectively quadrupling the cost of natural gas). In contrast, for firms purchasing gas from a local distribution company, there is little or no ability to buy in defiance of a curtailment order, and customers are required to honor the curtailment order. If they do not, the customer is subject to huge penalties for amounts taken above the contract quantity.

For interruptible service, or for that portion of a supply contract that is interruptible, both interstate and local distribution would be "halted" or "restricted" under Operational Flow Order (OFO) conditions (or pre-OFO conditions). Because many large consumers of natural gas utilize contracts that combine firm and interruptible transportation, an OFO represents an unpredictable constraint on a firm's ability to operate their plant at optimal levels. Those firms whose natural gas supply contracts consist entirely of firm delivery, this would an infrequent event.

Considering these issues with the current definition, CIBO recommends that EPA address the following during the administrative reconsideration process:

- EPA should not restrict the ability of natural gas consumers to obtain the most appropriate available gas purchasing contract arrangement for their purposes.
- EPA should allow use of backup liquid fuel firing under those situations where the supply of natural gas is restricted to the boiler/process heater operator under any purchase contract arrangement to the extent that either a very high cost or a penalty would be involved for continued natural gas use at pre-restriction levels. Note that gas suppliers do not have automatic shutoff capability, but rather they rely on customers taking appropriate action to reduce gas use when needed.
- The intention of the new sentence added to the definition of "period of natural gas curtailment or supply interruption" in the final rule per the comment and the EPA response to that comment noted above appears to be to clarify that the act of establishing a natural gas purchase contract itself is not the action being used to trigger the curtailment or interruption, but that only the action of the supplying entity to restrict gas consumption under any available contract arrangement is the triggering event relative to gas supply to the facility.
- However, the following EPA statement in the preamble creates confusion: "… the definition of ''Period of natural gas curtailment'' was revised to clarify that contractual agreements for curtailed gas usage or fluctuations in price do not constitute periods of gas curtailment under the scope of this regulation." This could be interpreted to mean that if an entity contracted for interruptible gas, that the use of backup liquid fuel during periods of supplier curtailment would actually not be allowed under this rule. It is hard to believe that EPA would intentionally use this hammer to push boiler and process heater operators to higher priced contracts for firm gas, when such action would directly impede gas suppliers from being able to provide adequate gas supplies to other "critical" customers (e.g. residential consumers). CIBO assumes this was not EPA's intent, but rather EPA was trying to address "hedging" or other market transactions not associated with supply limitations. In any case, EPA must provide further clarification so that owners/operators are not disadvantaged in the natural gas market simply by trying to maintain high facility uptime with use of backup fuels.

Furthermore, EPA did not address the issue of on-site natural gas system emergencies that might occur and restrict the ability to burn natural gas in boilers and process heaters. Similar to natural gas supplier emergency conditions such as equipment or piping failures, similar failures can occur within the affected facility fenceline. If and when such failures occur, it is necessary for operators to cease firing of natural gas in certain affected units to maintain safety of personnel and effect repairs. Where backup fuel is available, use of that fuel could allow facilities to remain in operation and prevent facility shutdowns, severe equipment problems and unsafe conditions due to loss of steam or process heat. EPA should allow use of backup liquid fuel under similar conditions as supply curtailments or interruptions for emergencies within the plant site that necessitate ceasing use of natural gas on specific affected units.

EPA should modify the wording of the final rule to clarify that nothing in the final rule impacts the ability of natural gas consumers to utilize any available natural gas purchase contract arrangement and that the curtailment or supply interruption provision applies similarly to any purchase contract arrangement. The definition should be modified to indicate that the period of natural gas curtailment or supply interruption means a period of time during which the supply of natural gas to an affected facility is halted, restricted, or penalized for reasons beyond the control of the facility. The last sentence should be deleted or modified to indicate that an increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment. EPA should clarify that financial penalties for exceeding curtailment events (such as “Operational Flow Orders”, etc.) described in tariff agreements regulated by FERC are considered to be supply interruptions beyond the control of a facility. EPA should also clarify that on-site natural gas system emergencies or equipment failures can be similarly treated as periods of supply interruption.

XIII. ISSUES NEEDING CLARIFICATION

In addition to clarity on these specific areas of ambiguity, EPA should supply sources with a succinct summary of all compliance deadlines to assist their compliance with the final Boiler Rule. EPA's final Boiler Rule contains various compliance requirements that are vague or subject to different interpretations. These inconsistencies in the Rule place an unjustifiable burden on sources, which face the challenge of attempting to comply with a rule that is facially unclear. The Boiler Rule should clearly state applicable timelines necessary for compliance.

A. It is Unclear When the Initial Tune-Up is Required.

The Final Rule creates a work practice standard that requires specific units to undergo an annual or biennial tune-up in lieu of emission limits. However, the Rule is unclear when the initial tune-up is required and EPA's failure to clarify this requirement makes it infeasible for sources to accurately and timely comply with the Rule.

In Section 63.7495(a) the Rule calls for new units or those reconstructed after June 4, 2010 to comply with the Rule's provisions 60 days after publication or upon startup, whichever is later. (319) However, Section 63.7510(e) initial compliance requirements for emission limits, states that all new or reconstructed units must demonstrate initial compliance no later than 240 days after publication in the Final Rule or within 180 days after startup, whichever is later. (332) The

tune-up work practice requirements are intended to replace emission limits and thus the timeline in Section 63.7510(e) has caused sources confusion as to which compliance deadline applies for tune-ups. (22, 23) This ambiguous and inconclusive language in the Final Rule regarding the tune-up requirement for new and reconstructed sources makes determining compliance requirements difficult and places an unjustifiable burden of Rule interpretation on sources.

B. It is Unclear When the Energy Assessment Must Be Met.

Likewise, the Final Rule fails to identify when the energy assessment, a one-time requirement for existing boilers and process heaters, must be met. The Rule generally discusses compliance for existing sources, but fails to clearly state the exact compliance timeframe for the energy assessment compliance.

XIV. REVISIONS ARE NEEDED TO THE DEFINITION OF HYBRID SUSPENSION/GRATE BOILERS.

EPA extended a request that bagasse fired boilers be included in a new sub-category to include any biomass fired in suspension/Dutch Oven Units and Suspension/Grate Boilers. CIBO supports the extension of the definition to all biomass fuels. However, the definition of biomass/suspension/grate boilers is a little unclear and EPA should address this issue during administrative reconsideration.

The definition in 76 Fed Reg. 15,634 states that "hybrid suspension/grate floor burners are designed such that the wet fuel first undergoes drying and then combustion in suspension within the furnace, with any remaining unburned fuel falling on to the grate to complete combustion." This definition describes what happens in the type of stoker known as a "spreader stoker" as opposed to a "mass burn," "step grate" or "underfeed retort" type of stoker.

However, the definition could also mean a boiler with an independent suspension burner firing over a grate. CIBO requests that the definition of a "suspension/grate" boiler specifically include the words "spreader stoker" as a type of combustion system in a suspension/grate boiler in addition to those with independent suspension burners.

XV. OUTPUT-BASED ALTERNATIVE

Sources were not given notice and comment opportunity on the output-based alternative in the final rule. Through reconsideration, EPA can alter this option to create a useful alternative for sources. Specifically, EPA should clarify if a source still gets credit if it wants to install co-generation unit.

There is no real advantage or logic seen in the output-based limits versus heat input based. This approach requires sources to obtain and use credits in a process which appears overly burdensome and of no practical utility. Emissions credits requirements appear to impose substantial effort in order to achieve very limited emission credit benefits for use with output based limits. 76 Fed. Reg 15675-76. Furthermore, EPA illegally creates an emission credit

opportunity for sources to lower their emission compliance obligation. This option has no basis in an air toxics rule.

Furthermore, it appears that the output based emission limits and heat input based limits contained in Tables 1 and 2 are inconsistent. 76 Fed. Reg. 15,687-91. EPA needs to clarify these issues.

XVI. CEMS

A. The CEMS QA/QC Requirements are Confusing and Extremely Burdensome on Sources.

Many industrial boilers and process heaters are subject to a variety of federal and state regulations, many of which require slightly different data reduction requirements and quality assurance / quality control requirements for CEMS systems generating that data. For the affected source, it is extremely burdensome to train personnel how to treat a raw data signal from a CEMS differently depending on which rule it will be use to demonstrate compliance. For example, consider that one invalid hour of diluent gas data (e.g. CO2) could be treated differently for each of CAIR NOx, NSPS for SO2 and NOx, Part 98 GHG, State SO2 and NOx, and State monitor availability calculations. This complexity is magnified by the similar but not identical monitoring requirement differences in 40 CFR 75 Appendix A and B versus 40 CFR 60 (et al) and various state monitoring requirements.

Some sources subject to a patchwork of overlapping regulations have petitioned the EPA and their state regulators for permission to standardize some parts of their compliance assurance methods. One area where this can be reasonably accommodated is in the quality control and quality assurance requirements for the CEMS systems. EPA should anticipate this need and clearly and unambiguously allow sources to comply with the QA/QC protocols for existing and new CEMS that represent the agency's most up-to-date and comprehensive thinking on the subject: 40 CFR 75 Appendix A and B. Alternatively, EPA could allow sources with existing CEMS to adopt their current QA/QC protocols in their entirety, thus avoiding the burden of learning new QA/QC procedures in addition to learning new monitoring equipment and managing new compliance assurance processes. Giving sources this option will not impose any cost burden on EPA or delegated state authorities, and would allow sources to exercise such discretion where it makes sense (e.g. cost effective management of limited compliance resources) to do so.

Further efficiencies can be realized, and potential errors reduced, by standardizing the data reduction required of affected sources for the individual standards put forth in Subpart DDDDD. Requiring some values to be reduced to 12-hour block averages (e.g. wet scrubber pressure drop), while other standards are determined on a daily block average (opacity for fabric filter or electrostatic precipitator controlled units), while yet others are determined on 30 day rolling averages (e.g. PM CEMS for units > 250 MMBtu/h) imposes upon affected sources a bewildering array of data handling requirements in addition to the patchwork of requirements already in existence (e.g. 3h averages for NSPS Subpart D, or 30 day rolling averages for NSPS Subpart Db, or 6m averages for opacity, etc). EPA should relieve some of the considerable

administrative burden, and risk of error, by establishing that all data collected by CEMS and parametric monitoring systems to demonstrate compliance with standards in this rule be reduced to 30 day rolling averages for purposes of demonstrating compliance.

B. EPA Should Not Require PM CEMs.

EPA included in the final rule the requirement that particulate matter CEMS (PM CEMS) be installed on units > 250MMBtu per hour to satisfy continuous compliance requirements for particulate matter emissions. This is similar to the proposed rule requirements. CIBO and others provided comments relative to use of PM CEMS, but EPA did not address key items in the preamble or Response to Comments documents.

The installation and annual certification expenses for the PM CEMS are extreme and unreasonable. EPA has failed to provide any technical information regarding the suitability of PM CEMS as compliance monitors.

EPA's requirement that PM CEMS should be used to demonstrate continuous compliance on all solid fuel boilers larger than 250 MMBtu/hr is arbitrary and not supported by any data. There is no published information documenting that PM CEMS installed on multi-fuel boilers can measure PM emissions accurately and demonstrate compliance with PS 11. There are also several significant issues with installing PM CEMS on multi-fuel boilers and biomass boilers commonly used in the forest products industry that need to be addressed before installation of such systems.

EPA has failed to document that PM CEMS are sufficiently precise and accurate to determine compliance with the applicable standards. PM CEMS are required to meet the requirements of PS 11. PS 11 specifications include a correlation coefficient of =0.85 between measured and predicted stack gas PM concentrations. A confidence interval (95%) mid range value at the mean PM CEMS response of ±10% of the emission limit, and a tolerance interval mid range 95% confidence interval value such that 75% of all possible values are within 25% of the PM emission limit. This suggests a very high probability that many CEMS PM measurements that show up as exceeding the standard would actually be below the emission standard. In this situation, operators would be forced to make changes to a control device or even shut down the boiler if these changes did not cause a response, even though PM emissions were in compliance with the standard. This is in direct conflict with the current view of compliance. If it is EPA's desire to use PM CEMS for demonstrating compliance, it must show how compliance would be determined with devices with such a high error band

Absent the questions about the feasibility of installing PM CEMS on biomass and multiple fuel boilers, we believe that these monitors are not necessary, given the annual PM testing requirements and continuous parametric and opacity/bag leak detector monitoring.

We recommend that prior to requiring the installation of CEMS on multi-fuel boilers, biomass boilers, or CISWI sources, EPA needs to (1) establish performance specifications for stack gas moisture monitors, and (2) determine the accuracy and precision of PM CEMS on biomass and multi-fuel boilers and CISWI sources. EPA should also use data from existing PM CEMS to

determine variability impacts for inclusion in establishing the floor when PM CEMS are required. If PM CEMS are required for specific units, EPA needs to include consideration of actual PM CEMS response for units in the particular subcategory firing applicable fuels. It is inappropriate to only use 3 limited time reference method runs to establish an emission limit that will need to be met using continuous monitoring. Reference method testing at high load steady state conditions does not represent actual average emissions as would be measured over all operating conditions with a CEMS.

With respect to the requirements associated with PM CEMs, CIBO is also concerned with the anticipated high cost and ability to comply with the applicable performance specifications under normal operating conditions. For example, some CIBO member facilities include common stacks that serve as the exhaust for both coal and oil boilers. In some situations, the only location that would likely meet the installation requirements for the PM CEMs is on this common stack, which would include emissions from the oil-fired boilers that are subject to different requirements than the coal-fired boilers. This would likely render the PM CEMs data invalid during those periods when the oil-fired boilers are in operation. CIBO members are also concerned with the ability of PM CEMs to accurately quantify emissions over the range of operating conditions that may be experienced when one or both of the coal-fired boilers are exhausting through the common stack.

CIBO also supports the information provided in the AF&PA et.al. petition for reconsideration relative to PM CEMS issues.

XVII. FUEL ANALYSIS

A. The Requirement to Establish a Maximum Chlorine Fuel Input Limit is Untenable.

Many solid-fuel industrial boilers are required to control emissions of sulfur dioxide (SO_2) to comply with state and/or federal regulations (e.g. NSPS Subpart Db, Individual SIPs, etc). Most of these units demonstrate compliance with SO_2 emission standards by monitoring SO_2 using one or more CEMS. EPA has adopted the position that "SO2 is a suitable surrogate for the acid gas HAP" for EGU's in Subpart UUUUU, published on May 3, 2011. EPA further explains its thinking:

> Most, if not all, coal-fired EGUs and solid oil-derived fuel-fired EGUs already have emission limitations for SO2 under either the Federal NSPS, individual SIP programs, or the Federal ARP and, as a result, have SO2 emission controls installed. Further, again most, if not all, coal-fired EGUs have SO2 CEMS installed and operating under the provisions of one of these programs. Thus, as SO2 is a suitable surrogate for the acid gas HAP, it could be used as an alternate equivalent standard to the HCl standard for EGUs with FGD systems installed and operated at normal capacity. An SO2 standard would ensure that equivalent control of the acid gas HAP is achieved, and some facilities may find it preferable to use the existing SO2 CEMS for compliance purposes rather than having to perform the manual HCl compliance testing. As noted elsewhere, this approach

does not work for EGUs that do not have SO2 controls installed and, thus, those EGUs may not utilize the alternate SO2 limitations.

76 Fed. Reg. 25,059. EPA provided a framework for using SO_2 compliance as a surrogate for acid gas HAP compliance in Tables 1, 2 and 5 (excerpts below):

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS[1]

If your EGU is in this subcategory . .	. For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) with the test methods in Table 5 . .
1. Coal-fired unit designed for coal □8,300 Btu/lb.	b. Hydrogen chloride (HCl) ... OR Sulfur dioxide (SO2) 6	0.0020 lb per MMBtu or 0.020 lb per MWh. 0.20 lb per MMBtu or 2.0 lb per MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 60 liters per run. SO2 CEMS.
2. Coal-fired unit designed for coal < 8,300 Btu/lb .	b. Hydrogen chloride (HCl) . OR Sulfur dioxide (SO2) 7	0.0020 lb per MMBtu or 0.020 lb per MWh. 0.20 lb per MMBtu or 2.0 lb per MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 60 liters per run. SO2 CEMS.
5. Solid oil-derived fuel-fired unit ...	b. Hydrogen chloride (HCl) . OR Sulfur dioxide (SO2) 8 .	0.0050 lb/MMBtu or 0.080 lb/GWh 0.40 lb/MMBtu or 5.0 lb/MWh ...	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 60 liters per run. SO2 CEMS.

[1] 76 Fed. Reg. 25,126 – 25,128.

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE STACK TESTING REQUIREMENTS[2]

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .10
5. Sulfur dioxide (SO2)	SO2 CEMS	a. Install, operate, and maintain the CEMS ..	PS 2 or 6 at 40 CFR part 60, Appendix B of this chapter and QA Procedure 1 at 40 CFR part 60, Appendix F of this chapter.
		b. Install, operate, and maintain the diluents gas, flow rate, and/or moisture monitoring systems.	Section 4.1.3 and 5.3 of Appendix A of this subpart.
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb per MMBtu emissions rates or lb/MWh emissions rates.	Method 19 F-factor methodology at 40 CFR part 60, Appendix A–7 of this chapter, or calculate using mass emissions rate and electrical output data.

Because EPA concluded that using SO_2 as a surrogate for acid gas HAP "would ensure that equivalent control . . . is achieved" for EGUs equipped with FGD systems, it is self-evident that using SO_2 as a surrogate for industrial boilers similarly equipped with FGD systems would also provide equivalent control of acid gas HAP in this population of units. And much like EGUs, industrial boilers equipped with FGD and SO_2 CEMS would find it logical and cost effective to utilize their existing equipment, monitoring systems, and compliance assurance processes to demonstrate compliance with acid gas HAP such as HCl.

To reduce the burden on sources and make cost-effective use of previously installed equipment and compliance assurance processes, EPA should revise Subpart DDDDD to incorporate the logic used in Subpart UUUUU that acknowledges the efficacy of FGD systems installed for the control of SO_2, or other acid gases, in the control of acid gas HAP addressed in this rule. EPA

[2] 76 Fed. Reg. 25,129 – 25,131.

should further incorporate a framework into Subpart DDDDD for compliance with a SO_2 emission standard in lieu of "manual HCl compliance testing" as has been provided in Subpart UUUUU. EPA could establish a logical framework whereby individual sites could characterize the relationship between the removal efficiency of SO_2 and the removal efficiency of acid gas HAP, establish a standard for SO_2 that provided equivalent control of HCl, and allow compliance with this derived SO_2 standard in lieu of "manual HCl compliance testing". However, because EPA's logic, language, emissions standards and performance testing requirements I Subpart UUUUU are both clear and reasonable, CIBO recommends that EPA adopt identical language and requirements (e.g. Tables 1, 2 and 5) into the Subpart DDDDD: A 30 boiler operating day average of not more than 0.20 lb/MMBtu.

Because industrial boilers and process heaters utilize multiple fuels on a more widespread basis than is typically encountered in EGUs, industrial units are more likely than EGUs to be affected by the provisions of Subpart DDDDD governing multi-fuel units found in §63.7530. Paragraph §63.7530(b) requires that the owner must "conduct fuel analyses according to §63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1)...", which explains how to establish the maximum chlorine fuel input limit. This provision is intended to ensure that units burning multiple fuels will not emit more HCl than was demonstrated during the annual performance test. However, units that comply with acid gas HAP emission standards by utilizing a FGD system, and that demonstrate compliance using SO_2 CEMS, will directly measure the controlled emission no matter what concentration of Cl was present in the various fuels fired. EPA should therefore relieve units that choose to comply with SO_2 CEMS of the burden of establishing a maximum chlorine fuel input limit as described in §63.7530(b)(1).

B. The Fuel Analysis Requirement Contained in § 63.7530(b) is Burdensome on Sources.

Many industrial boilers and process heaters utilize multiple fuels due to site-specific conditions or legacy design features. For units that fire multiple fuels, paragraph §63.7530(b) requires that the owner must "conduct fuel analyses according to §63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) and (b)(2)...." Paragraph §63.7530(b)(2) explains how to use the fuel analyses described in §63.7521 to establish a maximum mercury fuel input level. This requirement is particularly problematic for solid-fuel fired units firing coal. The concentration of various coal properties, including mercury, varies widely between basins (e.g. Central Appalachian versus Illinois Basin versus Powder River Basin), within basins (e.g. county by county, mine by mine, etc.), and even within individual seams. Units that source coal from multiple suppliers covering a diversity of geographic areas, individual mines and numerous seams are thus subject to considerable variability of mercury concentrations within their fuel shipments. For a unit that fires multiple fuels, one of which is coal sourced from a variety of mines, the requirement set forth in §63.7530(b)(2) to establish a maximum mercury fuel input level is extremely problematic. A unit that establishes such a maximum mercury fuel input level is in effect required to adjust its procurement specification for coal to match the mercury measured during its annual stack test. Given that the annual performance test represents only a

few hours operation out of potentially 8760 hours of operation in any given year, and one portion of a fuel shipment out of dozens or hundreds (or more) throughout the year, the source undertakes a significant risk of establishing a fuel specification for mercury that is not representative of what its "typical" fuel might otherwise look like.

To the source, such an outcome could significantly restrict the pool of potential suppliers capable of meeting this fuel specification, which would reduce the sources purchasing power in the marketplace and drive up its delivered costs. It is conceivable that a source might even have to renegotiate or terminate pre-existing contracts, with unpredictable legal and financial ramifications. The source would be forced to evaluate whether it could accept that year's new maximum mercury fuel input level, and its attendant impacts on potential fuel suppliers, or contract to repeat the performance test in hopes of a better outcome allowing more fuel sourcing flexibility.

Sources will attempt to minimize this risk by attempting to "cherry pick" the worst (i.e. highest mercury concentration) fuel possible to combust during its annual performance test in order to maximize the procurement flexibility during the subsequent year of operation. The process of "cherry picking" fuels for testing can be expensive (e.g. special sourcing arrangements, storage fees, demurrage, additional laboratory testing, etc.) and can significantly complicate the fuel procurement and logistics of a site, regardless of its size or complexity. "Cherry picking" the worst fuel also runs counter to EPA's broader mandate to reduce emission of air toxics, but practical experience in risk management demonstrates that this is the inevitable outcome for units that burn multiple fuels.

EPA should allow sources the option to monitor emissions at the stack with a mercury CEMS as an alternative method to ensure compliance with the standard. While some sources may prefer to "cherry pick" fuels for annual performance tests rather than undertake the cost and ongoing burden of monitoring mercury emissions with a CEMS, some sources will determine through internal analysis that installing and operating mercury CEMS is the best (i.e. most cost-effective) method of managing that risk. In those cases, both the source and EPA will benefit from this flexibility. EPA will further benefit by gaining some continual assurance of compliance, whereas the current structure of the rule provides only annual demonstrations of compliance.

CIBO recommends that EPA allow sources the option of complying with the mercury standard established in Table 2 for solid fuel units of Subpart DDDDD by utilizing data generated from a mercury CEMS or sorbent trap system, reduced to a 30 operating day rolling average, as described Table 5 and Appendix A of Subpart UUUUU:

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE STACK TESTING REQUIREMENTS[3]

To conduct a performance test for the following pollutant . . .	Using . . .	You must . . .	Using . . .10
4. Mercury (Hg)	Hg CEMS	a. Install, operate, and maintain the CEMS	Sections 3.2.1 and 5.1 of Appendix A of this subpart
		b. Install, operate, and maintain the diluents gas, flow rate, and/or moisture monitoring systems.	Section 4.1.3 and 5.3 of Appendix A of this subpart Section 6 of Appendix A of this subpart
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb per MMBtu emissions rates or lb/MWh emissions rates.	
	OR		
	Sorbent trap monitoring system	a. Install, operate, and maintain the sorbent trap monitoring system.	Sections 3.2.2 and 5.2 of Appendix A of this subpart. Section 4.1.3 and 5.3 of Appendix A of this subpart.
		b. Install, operate, and maintain the diluents gas, flow rate, and/or moisture monitoring systems.	Section 6 of Appendix A of this subpart.
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb per MMBtu emissions rates or lb/MWh emissions rates.	

C. EPA Needs to Clarify the Monthly Fuel Analysis Requirement.

[3] 76 Fed. Reg. 25,130 – 25,131.

The text of the final Boiler Rule and its preamble are not consistent with regards to the monthly fuel analysis requirements for those units that choose not to conduct a performance test for Hg and Cl. Furthermore, if a site routinely burns a solid or liquid fuel in tandem with a Gas 1 gas (such as natural gas or refinery gas), it is not clear whether that site must analyze both the gas (for Hg and Cl) and the solid/liquid on a monthly basis. EPA needs to clarify these issues.

D. Few Laboratories Can Meet the Standards Set Forth By EPA.

Table 6 in the final Boiler Rule requires sources that wish to consider non-natural gas or non-refinery fuel gas streams as other Gas 1 fuels use specified test methods for H2S and Hg. 76 Fed. Reg. 15,694-695. Through the course of evaluating potential laboratories for H2S analysis, very few laboratories are able to meet the required standards or determine the definition of equivalent. In addition, no laboratory has been identified that can meet the Hg analytical test methods for gaseous fuels as referenced below:

- Mercury Test Methods - ASTM D5954,ASTM D6350, ISO 6978-1:2003(E), or ISO 6978-2:2003(E) or equivalent
- H2S Test Methods - ASTM D4084 or equivalent

Since very few laboratories are able to meet these specific test methods, EPA should expand the approved test method protocols to accommodate the required testing. EPA should also clarify the term "equivalent" in Table 6 so that industry and laboratories clearly understand which alternate test methods are acceptable.

Other gas 1 streams from processing units within the petrochemical industry contain organic compounds that can condense after capturing the sample in an approved container for analysis. Reheating these containers to vaporize condensed liquids presents significant safety concerns associated with heating elements in the presence of compressed explosive gasses. In-situ or on-line analyses are impracticable because of safety concerns associated with operating heated sample lines in the vicinity of an explosive gas stream. Thus, safety issues with sampling and analyzing for H2S and Hg can lead to compromised results.

EPA should consider allowing industry to utilize engineering and process knowledge where no additional sulfur or mercury is introduced into the process to demonstrate compliance with the fuel specifications for "other gas 1 fuels." Examples of engineering and process knowledge that could be utilized include, but are not limited to, process knowledge for facilities utilizing pipeline, sweet natural gas as a feedstock without addition of mercury containing compounds to the process, piping and instrument diagrams (P&IDs) showing piping configurations, engineering calculations demonstrating concentrations of H2S and Hg, and standard operating procedures for the addition of miscellaneous materials to the process.

XVIII. ADDITIONAL ISSUES

A. ESP Power Over Load and Coal Quality Variation.

Secondary power consumption by an Electrostatic Precipitator is directly influenced by the design of the precipitator, the quantify of particulate being captured, and the resistivity of the particulate matter being captured. While the quantity of particulate matter to be collected varies directly with unit load, the resistivity of the particulate matter is determined by a combination of factors that are not load-related. Resistivity is influenced by the size distribution of the particles, the amount of sulfur present in the fuel, the amount of unburned carbon present in the ash particles, and the temperature and humidity of the flue gas.

By establishing a minimum secondary power during a performance test, EPA is in effect limiting the operating parameters of the unit. By way of example, if an annual performance test established a minimum secondary power at maximum load, the unit could find it impossible to maintain that minimum power level when operating at reduced loads (e.g. particulate loading was reduced). A unit would also find it challenging to comply with a minimum power requirement when the ash resistivity changed significantly (e.g. fuel received with higher moisture, such as when the fuel had been exposed to rain). EPA should revise the requirement for establishing a minimum precipitator secondary power parameter to allow a source to characterize the secondary power consumption of the precipitator over a range of expected loads, and maintain compliance with a parameter that reflected secondary power consumption normalized for unit load.

B. EPA Ignored Comments Regarding the Use of Continuous Cross Belt Samplers.

The vast majority of sources require that fuel procured from outside the affected source's direct control conform to some quality specifications. Many sources require that fuel quality testing (e.g. routine sampling, laboratory test methods, data reduction and reporting) and quality assurance (e.g. random sampling, laboratory audits, etc.) be conducted by third party laboratories to ensure impartiality and consistency. For those sources that obtain quality assured analyses of fuel constituents (e.g. Hg or Cl) conducted by third-party laboratories, EPA should allow the use of these third-party analyses in lieu of the requirements set forth in §63.7521(c).

For those sources that do not obtain fuel quality data from third parties, or that elect to do their own fuel sampling for purposes of complying with this subpart, EPA should not attempt to restate in §63.7521 the cumulative experience captured in the vast libraries of ASTM, ASME, EPA (and others) test codes and methods. Rather EPA should require that fuel sampling techniques ensure representative samples are taken, and that the source be required to submit a sampling plan to the Administrator prior to a performance test. This would enable each source to adopt sampling methods that were tailored to the source's particular equipment arrangements, while still ensuring EPA's interest in obtaining representative data by including EPA in the review and approve step for the affected source. By balancing EPA's need of representative data with each source's unique knowledge of its equipment, the interests of both can be best served. An example of problems with the EPA approach is the requirement to stop a coal belt to take a coal sample, when some systems utilize automatic cross belt samplers that take the sample while the belt remains in operation- such systems cannot be prohibited.

C. EPA Needs to Clarify Table 8 With Regard to "12-hour Block Average".

In Table 8 of the final Boiler Rule fails to include the word “block” in items 3c, 4c, 5c, 6c, and 9c. 76 Fed. Reg. 15,697. EPA needs to clarify this oversight and upon reconsideration insert the word "block" to read “12-hour block average” in items 3c, 4c, 5c, 6c, and 9c. This is needed for consistency and to avoid confusion since the word is already included in 8c.

D. Definition of "Hot Water Heater"

The proposed Boiler Rule provided an exemption for hot water heaters. 75 Fed. Reg. 32,050. EPA defined water heater under the proposed Boiler Rule to mean

> a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210° F (99° C).75 Fed. Reg. 32,064.

Despite the fact EPA has no data on the number of units that exist and the fact that the Agency has not recognized the high cost of regulating these units for their infinitesimal emissions, the definition was not changed in the final rule, other than to include tankless units. EPA needs to consider these issues during the administrative reconsideration process. EPA should expand the definition to include natural gas or distillate fuel oil fired circulating hot water systems no larger than 10MMBtu/hr heat input that are used for domestic (e.g., washroom, cafeteria) or space heating purposes. This would eliminate the need to spend time or effort on units with insignificant emissions.

E. EPA Should Reconsider its Rationale for Denial of the Comment to Eliminate the Emissions Averaging Test at Full Capacity.

CIBO and other commenters made several comments concerning the emissions averaging provisions of the proposed rule. EPA made essentially no changes to the emissions averaging provisions, other than to clarify that all solid fuel boilers are now in the same subcategory and could emissions average with one another.

Shown below from the Response to Comment document is one of those comments and EPA’s response.

> **Commenter Name:** Stephen R. Gossett
> **Commenter Affiliation:** Eastman Chemical Company
> **Document Control Number:** EPA-HQ-OAR-2002-0058-3137.1
> **Comment Excerpt Number:** 5
> **Comment:** Compliance should be based solely on actual emissions.

The proposed provisions require (1) a demonstration that the average weighted emissions is less than 90 percent of the applicable emissions limit assuming each unit is operating at its maximum rated heat input capacity (see Equation 1) and (2) a demonstration each calendar month that the average weighted emissions is less than the applicable emissions limit using the actual heat inputs for that month.

There is no rationale for the first test and it should be eliminated. Other rules that allow emission averaging (again, see the HON), include no such requirement. Such a requirement could be unduly restrictive. For example, a facility may have one older unit and a newer unit which they would like to average. The older unit may have a much lower capacity factor (ratio of actual usage divided by rated capacity) than the newer one. Older units typically have much more space constraints and a facility may be facing steep compliance costs to bring the older unit into compliance and may have an opportunity to over-control the newer unit. Given that the newer unit has a longer remaining life expectancy, such a facility should be incented to over control the newer unit. Yet, Equation 1 may block the facility from taking advantage of the emission averaging flexibility, especially if the older unit has a comparable or even higher rated capacity than the newer unit.
Response: *See response to EPA-HQ-OAR-2002-0058-2808.1, excerpt 30 for the discount factor. The maximum rated heat input capacity was also used in the vacated rule in order to ensure adequate protection of the environment. Most of the commenters requesting for use of the actual instead of maximum rated heat input capacity were concerned with limited use units which have now been addressed using a separate subcategory. EPA does not agree that the intent of the MACT program is to allow infrequently used, but older coal units to participate in emissions averaging unless they can demonstrate that under maximum operating conditions the unit can meet the emission limit under the emissions averaging provision.*

EPA's response is arbitrary and capricious. The commenter was simply giving an example of where, except for the requirement to pass the emissions averaging test at rated design capacity, the emissions averaging provisions could enable a cost-effective option for older units that are not used as much as newer, more efficient units. The intent of emissions averaging has to be to allow under-control of some units and over-control of others such that the net emissions are no more than would be required without emissions averaging. Whether the unit is old, small, used seldom, or used often is not the real issue. The issue is affording sources the opportunity to seek a cost-effective solution for their particular circumstances. EPA's requirement that such units be assumed to operate at rated capacity as a prerequisite to participating in an emissions average is arbitrary. What matters is the actual usage rate and the relative emission rates of the units included in an average. The final rule's treatment of limited use units (those used less than 876 hours per year) does not alleviate this barrier to use of emissions averaging for units that don't qualify as limited use. CIBO requests EPA reconsider inclusion of this test in the emissions averaging provisions.

XIX. LANDFILL GAS

A. The mercury and H_2S concentration qualifiers for subjecting Gas 2 gases to Gas 1 standards are arbitrary.

In the proposed rule EPA defined the Gas 1 subcategory to include boilers and process heaters that burn at least 90 percent natural gas and/or refinery gas (on an annual heat input basis). The final rule adds a provision for gaseous streams otherwise considered to be in the Gas 2 subcategory to be included in the Gas 1 subcategory if they can meet specific mercury and H_2S emissions limits.

CIBO and many other groups submitted comments on the proposed rule explaining why landfill gas (LFG) and some other gases in the proposed Gas 2 subcategory should be included in the Gas 1 subcategory and regulated accordingly. Virtually all such comments were answered with the EPA response "… We are not finalizing limits for units firing natural gas, refinery gas, and other Gas 1 fuels. See preamble for rationale for selecting a work practice for these units".

The final rule preamble states that "EPA has determined to the extent that process gases are comparable to natural gas and refinery gas, combustion of those gases in boilers and process heaters should be subject to the same standards as combustion of natural gas and refinery gas". Further, EPA discusses why mercury and H_2S levels sufficiently similar to natural gas are relevant qualifiers.

EPA provided no opportunity for public comment regarding qualifying Gas 2 compounds into the Gas1 subcategory, as this scenario is provided for the first time in the preamble to the final rule. This justification is not a "logical outgrowth" of the proposed rule because commenters could not have reasonably predicted at the time of proposal that EPA might rely on delineations of whether natural gas is "sweet" or "sour" in justifying regulating Gas 2 as Gas 1 in the final rule. The published limit of 4 ppm H2S appears especially arbitrary since the Gas 1 category includes refinery gases which can contain as much as 160 ppm of H2S.

Additionally, EPA notes in their Revised MACT Floor Analysis Document that "Based on the results of the selected gas specification for mercury, which will determine whether a gaseous fuel belongs in the gas 1 or other gas 2 fuel category, we determined that most gaseous fuels other than coke oven gas and blast furnace gas would pass the fuel specifications in the final rule, so only tests firing coke oven gas either alone or in combination with blast furnace gas or other gaseous fuels were considered when calculating the MACT floors for the other process gas (gas 2) subcategory". This brings into question whether the appropriate sources were used to develop the MACT floor since EPA assumed most gaseous fuels "would pass the fuel specifications". Contrary to EPA's assumption, LFG, and presumably several other gases, are unlikely to pass the fuel specification for H_2S.

While it is admirable that EPA provides a pathway to control Gas 2 gases as Gas 1, the mercury and H_2S limits seem arbitrary and are not relevant to HAP emissions from landfill gas. Landfill gases generated from municipal landfills typically generate between 5 and 150 ppmv of H_2S. Since H_2S is not regulated under the CAAA 112 rules and has limited relevance to HAP

emissions other than partial conversion to SO2, its selection as a Gas 2 to Gas 1 qualifier seems to be arbitrary.

B. EPA did not gather enough representative data to adequately set Gas 2 subcategory limits.

Although EPA considered sampling data from several sites in order to set Gas 2 subcategory emissions limits, the sample data is grossly underrepresented with regard to landfill gas. It is our understanding that only one landfill gas site was included in EPAs MACT floor-setting emissions database for Industrial, Commercial, and Institutional Boilers and Process Heaters. That site, BMW of South Carolina, could not pass EPA's Final Gas 2 emissions limits for at least two pollutants. Although Gas 2 represents a wide array of gases, limiting landfill gas emissions sampling to only one facility is inadequate.

EPA's own EPA Landfill Methane Outreach Program (LMOP) encourages "the recovery and beneficial use of landfill gas (LFG) as an energy resource". Moreover, EPA has noted "LFG contains methane, a potent greenhouse gas that can be captured and used to fuel power plants, manufacturing facilities, vehicles, homes, and more". Certainly if EPA is insistent on including LFG in the Gas 2 subcategory then sampling data used to set the MACT floor warrants more than one emissions data point.

C. EPA did not adequately respond to comments requesting the inclusion of Gas 2 gases in the Gas 1 subcategory.

As noted above, many comments were submitted explaining why landfill gas and some other gases in the proposed Gas 2 subcategory should be included in the Gas 1 subcategory and regulated accordingly. EPA's limited response to comments were focused almost exclusively on providing the Gas 2 to Gas 1 qualifiers based on mercury and H_2S levels in the fuel gas stream. EPA did not address many of the additional reasons included in the comments explaining why Gas 2 gases should be included in, and regulated in the same manner as the Gas 1 subcategory.

These items briefly include:

1. It is not technically or economically feasible to control HAPs from Gas 2 units.
2. EPA did not take into account in the establishment of the Gas 2 MACT Floors the extreme diversity of Gas2 fuels and the units in which they are combusted.
3. Few, if any MACT floor sources can pass all of the Gas 2 limits from the same source.
4. Data quality errors exist in the MACT floor data, especially involving the handling of detection limit values.
5. It is likely that many of the gasses that are regulated under the Gas 2 category will simply flare the gas instead of combusting gas in boilers or process heaters for energy recovery. Nationally, this includes over 100 units burning LFG in boilers or process heaters – with more being added. This outcome results in increased NOx and CO2 emissions because of less complete combustion from the flares. Additionally greenhouse gas emissions would be increased from the combination of flared LFG and natural gas burned instead of LFG in industrial combustion units.

6. EPA's proposed definition for Gas 2 units does not include a *de minimus* threshold. Any miniscule amount of LFG mixed with natural gas, for instance, would be regulated in the Gas 2 subcategory.
7. HAP emissions from LFG combustion are not known to be a problem, and in fact, the top performing Gas 2 unit for mercury and for dioxins and furans was the BMW watertube boiler firing LFG.
8. The Gas 2 emission limits for new or existing units also include an unrealistically low CO limit of 3 and 9 ppmvd @ 3% O2, respectively that likely cannot be achieved by any boiler or process heater firing any percentage of LFG.
9. Some Gas 2 process gases present special safety problems relative to sampling and analysis using the test methods provided in the final rule by EPA. Those provided methods are designed to apply to pressurized flowing natural gas lines, not low pressure gaseous streams that might impose health impacts when released. EPA also needs to consider these issues and either provide applicable test methods or alternative approaches to compliance, the most appropriate being simply to treat them as Gas 1 with work practices.

   A facility had an indirect-fired process heater combusting biogas and was tested under the EPA's Section 114 Request for additional information where the CO was tested at about 90 ppm. It will be uneconomical to control the CO emissions to the existing unit Gas 2 CO emission limit of 9 ppmvd @ 3% O2. The facility will have to either flare the biogas or discontinue the use of that renewable fuel. The EPA should be encouraging the use of biogas and other renewable fuels without placing in doubt the regulatory viability of the continued use of these fuels. The net effect of these rules will strongly discourage the use of renewable fuels where the clear policy direction from Congress in RCRA and policy commitment of this Administration is to encourage the use of renewable fuels.

   EPA should therefore include Gas 2 gases in the Gas 1 subcategory and regulate them in the same manner.

CONCLUSION

For all of the foregoing reasons CIBO respectfully requests that EPA grant the Petition for Reconsideration.

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