**American Iron and Steel Institute**

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U.S. Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, DC 20460

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RE: National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters - Proposed Rule - 75 Fed Reg 32005 (June 4, 2010)

Ladies/Gentlemen:

The American Iron and Steel Institute (AISI) is pleased to submit comments on the subject proposed rule (Boiler MACT or Proposed Rule). AISI is the principal trade association representing the North American steel industry and represents member companies accounting for approximately 75% of the U.S. steelmaking capacity with facilities located in 33 states.

Most AISI member companies employ boilers or process heaters to generate steam and/or electricity. Many iron and steel facilities are by their nature major sources of hazardous air pollutants (HAPs) and are therefore significantly impacted by the Proposed Rule (Subpart DDDDD).

Iron and steel manufacturers are energy-intensive industries that utilize process gases and waste heat extensively to offset fossil fuel consumption. Since the process gases in our industry, notably blast furnace gas and coke oven gas, must be flared or otherwise combusted to meet environmental and safety requirements, the products of combustion are always being emitted. Utilization of the process gas as a fuel in a boiler or process heater allows the recovery of energy otherwise wasted. This displaces fossil fuel combustion and eliminates tons of greenhouse gas and other emissions associated with that fossil fuel use. The Boiler MACT has the potential to either support or obstruct energy recovery from process gases in our industry.

While the Proposed Rule includes several laudable provisions, we have significant concerns with the proposal because it would potentially impose stringent numeric emission limitations that would be difficult, if not impossible, to meet. We believe EPA has not amply justified the need to impose numeric limits on industrial boilers and process heaters. As described below, EPA has the legal discretion and technical justification to substantially reduce the burden of the standard while still providing ample protection to health and the environment. We begin with comments on issues of particular relevance to iron and steel operations and follow with general comments and recommendations in several key areas regarding the underlying EPA analysis for setting the proposed standards.

## IRON & STEEL INDUSTRY-SPECIFIC COMMENTS

### AISI Supports the Exclusion of Blast Furnace Gas in the Definition of Gaseous Fuels and the Exemption for Blast Furnace Stoves

As an initial matter, we support EPA's decision to exclude blast furnace gas from the definition of gaseous fuel. Blast furnace gas is generated as the blast furnace processes iron ore, carbon sources, and fluxes at high temperature to make molten iron. Blast furnace gas is scrubbed of dust particles and then burned primarily in the blast furnace stoves to generate the hot blast air used in the furnace. Excess blast furnace gas is typically routed to boilers to produce steam to drive turbines to provide the blast air and to provide steam for other plant processes. Excess blast furnace gas, if any, is flared.

In the 2004 Boiler MACT Rule,[1] EPA determined that it was appropriate to exclude blast furnace gas from the definition of gaseous fuel, because it "does not contain organic compounds" and organic HAPs are not generated by blast furnace gas combustion. *See* 2004 Boiler MACT Rule at 55230.[2] The characteristics of blast furnace gas have not changed since the 2004 rulemaking and we are aware of nothing in the record that would justify a departure from EPA's 2004 position on blast furnace gas. Due to its chemical make-up, it is proper for EPA to retain the blast furnace gas exclusion when it promulgates the final 2010 Boiler MACT Rule.

EPA has been consistent in its treatment of blast furnace gas combustion as a non-HAP fuel. In promulgating the Integrated Iron and Steel Manufacturing MACT

[1] National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule 69 FR 55218 (Sept. 13, 2004) ("2004 Boiler MACT Rule").

[2] *See also* OAR-2002-0058-0611 and OAR-2002-0058-0649 at 26 and 102 (explaining that BFG should not be included in the gaseous fuel definition because it "does not contain organic compounds" and that "blast furnace gas contains minimal or even no hydrocarbons").

Rule, EPA considered the blast furnace and blast furnace stoves for regulation and determined that blast furnace gas combustion at the stove was not a source of HAP emissions requiring an emissions limit or standard. *See* U.S. EPA, NESHAP for Integrated Iron and Steel Plants - Background Information for Proposed Standards, at 3-14 - 3-24, 4-14 (Jan. 2001). The 2004 Boiler MACT Rule acknowledged this prior assessment by excluding blast furnace stoves as "combustion units that are already or will be subject to regulation under another MACT standard under 40 CFR part 63." 69 FR at 55220. AISI supports EPA's decision to retain this exclusion of blast furnace stoves in the 2010 Boiler MACT and the decision to retain the exclusion of blast furnace gas from the definition of gaseous fuel.

**Additional Flexibility Is Necessary to Ensure That Units That Primarily Combust Blast Furnace Gas Are Excluded**

The Proposed Rule defines "blast furnace gas fuel-fired boiler" as a boiler "that receives 90 percent or more of its total heat input (based on an annual average) from blast furnace gas." 75 FR at 32063. That stringent 90% heat input limit does not reflect the operational reality of how blast furnace gas is and can be used at steelmaking facilities. Since blast furnace gas is a low BTU fuel (averaging 85-100 BTU/standard cubic foot), supplemental fuel combustion is necessary to support flame stabilization and to ensure complete combustion. While iron and steel manufacturers have every economic incentive to minimize the amount of supplemental natural gas, virtually all blast furnace gas-fired boilers are unable to sustain 90% blast furnace gas on an annual average heat input basis. Indeed, that would require the combustion of over 99% blast furnace gas on a volumetric basis due to the relatively high heat input value for natural gas (~1020 BTU/scf). Some blast furnace gas-fired boilers are also co-fired with coke oven gas (~500 BTU/scf). While EPA has acknowledged that blast furnace gas has a low heating value to volume ratio,[3] it has not properly assessed how this characteristic of blast furnace gas makes the 90% heat input level an impractical, if not impossible, standard to meet. In these situations, the blast furnace gas boiler exemption is negated and potentially subjects these units to Gas 2 or Liquid Fuel Fired limits.

We suggest that EPA consider a more reasonable threshold for the definition of blast furnace gas-fired boiler. If EPA wants to retain an annual heat input basis for the definition, the blast furnace gas percentage should be no higher than 50% of its total heat input (based on an annual average). When using natural gas as a supplement fuel, it would take over 90% blast furnace gas by volume to achieve this 50% heat input rate.[4] This may not be enough supplemental fuel allowance to ensure efficient combustion,

[3] OAR-2002-0058-0611 and OAR-2002-0058-0649; *see also* OAR-2002-0058-500.

[4] Assuming 90 BTU/scf for blast furnace gas and 1020 BTU/scf for natural gas, 50% blast furnace gas by annual heat input rate requires combusting 91.75% blast furnace gas by volume.

particularly in years when a blast furnace goes down for some period of time and the source of blast furnace gas is interrupted. Therefore, if EPA uses the 50% annual heat input threshold, the rule should also exclude from the annual heat input calculation all periods when a blast furnace is down. Alternatively, EPA could set the blast furnace gas fuel-fired boiler definition threshold on a volumetric basis. A boiler that is burning more than 50% blast furnace gas by volume on an annual basis is still primarily operated for the purpose of recovering energy from a clean fuel - blast furnace gas. A few days of blast furnace gas interruption can be accommodated because one-tenth of the natural gas by volume is needed to generate the heat input to replace blast furnace gas.

Given that blast furnace gas has always been considered a "clean" fuel, and its use should be encouraged - as should coke oven gas or other process gases as discussed below in our comments on waste heat boilers - EPA should amend the blast furnace gas fuel-fired boiler definition to ensure that iron and steel manufacturers can continue their energy recovery efforts. OAR-2002-0058-0611 and OAR-2002-0058-0649 at 39. Accordingly, the definition of a blast furnace gas fuel fired boiler or process heater should be amended in a manner similar to that for waste heat boilers, *e.g.*:

> *Blast furnace gas fuel-fired boiler or process heater* means an industrial/commercial/institutional boiler or process heater that combusts 50 percent or more by volume (based on annual average) of blast furnace gas.

With this modification, a final Boiler MACT rule will enable iron and steel manufacturers to continue their expanding efforts to use blast furnace gas to displace fossil-fuel combustion and to promote their continued energy recovery efforts that result in significantly reduced greenhouse gas and other emissions.

**Coke Oven Gas-Fired Boilers Should be Excluded from the Requirements of the Rule Because They are Regulated by Another MACT Rule**

At coke plants operated by integrated iron and steel producers and at stand-alone coke plants, off gases from coke ovens are either recovered as coke oven gas or are combusted to provide waste heat. A portion of the recovered gas or waste heat is returned to the ovens to sustain the cokemaking process and the excess coke oven gas or waste heat is utilized in boilers or for other combustion purposes in the facility.

The Proposed Rule states that any boiler listed as an affected source in another standard established under 40 CFR 63 is exempt from this rule. Because coke oven gas combustion is already regulated by another MACT rule (Subpart L at 40 CFR 63.307), as a threshold consideration, AISI seeks EPA confirmation that the proposed rule does not apply to coke oven gas-fired boilers. Subpart L requires that all excess coke oven gas (which can be interpreted as that not used to underfire the coke ovens themselves, *i.e.*, coke oven gas utilized in boilers) must be efficiently combusted. The rule requires a properly operated flare or an alternate system (approved by the Administrator) that achieves 98% destruction of the coke oven gas vented to the system. Since all boilers achieve 98% combustion efficiency when properly maintained and operated, EPA may use the proposed rule to impose an annual tune-up obligation as the sole requirement and approve the boiler as an alternate system under 40 CFR 63.307, which would clearly subject the coke oven gas-fired boiler to another MACT standard. This exclusion would support current efforts to encourage the energy recover of process gases to reduce fossil fuel consumption and greenhouse gas emission that would otherwise be emitted by flaring the coke oven gas and the fossil fuel used instead of coke oven gas in the boiler.

**Units That Recover Energy Otherwise Unused and Combusted Should Be Exempt in the Same Manner as Waste Heat Boilers**

The Proposed Rule excludes "waste heat boilers" from the definition of "boiler" because they are primarily used to recover "normally unused energy and convert it to usable heat." 75 FR at 32065. AISI supports the waste heat exemption because it is a proper approach to encourage the use and re-use of heat and steam to reduce demand for fossil fuel combustion. That same rationale applies equally to units that recover usable energy from excess coke oven gas or other process gases such as blast furnace gas and basic oxygen furnace off-gas. Excess coke oven gas or other process gases not otherwise used must be flared to meet environmental and safety requirements. However, such flaring results in the loss of valuable energy. By capturing those gases and moving their point of combustion to a boiler, previously unused energy is converted to usable heat. As a result, the energy recovered reduces the need to burn fossil fuels (coal, oil, and/or natural gas) to produce the steam and/or electricity generated by the process gas. Thus, the same rationale underlying EPA's exclusion of waste heat boilers from the Proposed Rule is equally applicable to units that recover energy from coke oven gas or other process gases. While it is logistically impossible to recover waste heat after a flare, the waste heat can be recovered by moving the point of combustion from the flare to an enclosed burner in the combustion chamber of a boiler or process heater.

Importantly, efforts made to switch from flaring coke oven gas or other process gases to combusting it in the more carefully controlled setting of a boiler will also benefit the environment in two ways. First, it will reduce the potential for inefficient combustion at the flare, which is exposed to wind and other elements that may interfere with complete combustion. Also, supplemental fuel at a flare is typically limited to the pilot light and is not available to help ensure a stable flame. As a result, EPA's emission factors assume up to 98% control of organic compounds from flares combusting gases with the heat values characteristic of coke oven gas. *See* EPA, AP-42 at 13.5-4 (citing EPA's Flare Efficiency Study, EPA-600/2-83-052). By contrast, properly tuned boilers achieve 99.9% combustion efficiency for organic compounds from gaseous fuels. *See* EPA, AP-42 at 1.4-3. This means that flares would be expected to emit 20 times the organic compounds that would be emitted from a boiler. Second, energy recovery in boilers will supplant the need for combustion of additional fossil fuels, thus eliminating the greenhouse gases, criteria pollutants, and HAP emissions associated with those fuels. For example, a 545 MMBTU/hr coke oven gas-fired boiler generating electricity will supplant 334,310 megawatt-hours of electricity previously purchased from the grid and reduce coal combustion by 260,000 tons per year. This one coke oven gas-fired boiler would reduce 357,240 tons of carbon dioxide emissions each year and many additional tons of other pollutants of concern.

If EPA finalizes a rule that subjects coke oven gas-fired boilers to the stringent numeric emissions limitations proposed for Gas 2 sources, the additional cost of controls would functionally eliminate these valuable efforts to reclaim energy. The U.S. Department of Energy has awarded competitive grant funds to energy recovery projects that convert flared coke oven gas to usable steam and electricity. The Proposed Rule would discourage the type of energy recovery project that DOE is actively trying to promote. This is because the annualized cost of control required to meet the Gas 2 emission limits exceeds the cost of replacement natural gas for many units. Facing this economic reality, coke oven gas will be flared and natural gas will be combusted to generate steam to the detriment of the environment and our national goals of energy independence.

The economic analysis is clear. The Proposed Rule sets numeric emission limits for 5 pollutants (PM, HCl, Hg, dioxin/furans, and CO). At this time, coke oven gas-fired units are not controlled for these compounds. Using EPA's projected cost of control (annualized capital cost plus annual operating cost) for each pollutant, including monitoring, recordkeeping and reporting, an AISI member company has calculated an annualized cost of control at $8.6 million for a single 650 MMBTU/hr unit combusting coke oven gas.[5] At a natural gas cost of $5/MMBTU (costs have been much higher in recent years), it is economically unreasonable for the boiler operator to use coke oven gas to displace the first 1,720,000 MMBTU per year of natural gas in this boiler or in blast furnace gas-fired boilers using coke oven gas, and the coke oven gas would be flared. The use of natural gas to replace coke oven gas in this situation would be to the detriment of the environment and our energy policies.

The constraint on available capital is an additional impediment to the installation of emission control equipment because increased natural gas consumption does not require a capital investment. Before a company will invest $8.6 million in annualized control costs for a single boiler, it will need to justify a return on the capital investment far greater than $8.6 million per year in displaced natural gas. Moreover, as discussed

[5] The capital cost for the unit is $27,747,000 and the annual non-capital cost is $5,678,000.

below, there is no expectation that expenditures of this magnitude will be sufficient to meet the proposed Gas 2 subcategory emission limits.

To avoid the creation of incentives to flare coke oven gas rather than reclaiming the unused energy it otherwise offers, EPA should expressly exempt units that recover waste heat from process gases otherwise flared by expanding the definition of waste heat boiler to add the following sentence:

> *"Boilers that use process gas that would otherwise be flared as their primary fuel are considered waste heat boilers."*

**Alternatively, Units Combusting Coke Oven Gas or Other Process Gases Should be Subject to the Same Work Practices as Natural Gas-Fired Units**

The work practices analysis set forth above is equally applicable to units that combust coke oven gas and other process gases. To the extent that the best performing units combusting those alternate fuels conduct tune ups (or other similar work practices) to achieve emissions reductions, EPA can promulgate those measures as work practice-based emissions standards to ensure continuous reductions in the quantity and/or rate of emissions of air pollutants under §112(d) and §302(k). As such, there is no need to delve into the prerequisites that exist under §112(h) for these units.

However, should the agency feel compelled to press forward with its §112(h) analysis we believe that the Proposed Rule's findings regarding the infeasibility of controlling and monitoring emissions from natural gas-fired boilers and process heaters are both appropriate and equally applicable to units fired with coke oven gas or other process gases. As found by EPA, work practices should supplant numeric emission limits on Gas 1-fired units because "[f]irst, the capital costs estimated for installing controls on these boilers and process heaters to comply with MACT limits for the five HAP groups is over $14 billion," a cost "higher than the estimated combined capital cost for boilers and process heaters in all of the other subcategories." 75 FR at 32025. Second, EPA found that proposing emission standards for gas-fired boilers and process heaters "would have the negative benefit of providing a disincentive for switching to gas as a control technique (and a pollution prevention technique)" and "may have the negative benefit of providing an incentive for a facility to switch from gas (considered a 'clean' fuel) to a 'dirtier' but cheaper fuel (*i.e.*, coal)." *Id.* As EPA correctly concluded, "[i]t would be inconsistent with the emissions reductions goals of the CAA, and of §112 in particular, to adopt requirements that would result in an overall increase in HAP emissions." *Id.*

These same arguments apply with even greater force to coke oven gas-fired and process gas-fired units. First, the costs of controlling coke oven gas-fired units are similar to the per-unit costs faced by Gas 1 units. Just like Gas 1 units, coke oven gas units are expected to face the need to install fabric filters for the control of particulate matter (PM), mercury (Hg), and dioxin/furan, as well as wet scrubbers to control hydrochloric acid (HCl) and an oxidizing catalyst to control carbon monoxide (CO) - all at a cost well beyond that already calculated by EPA. Second, imposing emission standards on these units would clearly incentivize operators to cease burning coke oven gas in preference for the fossil fuels that cost less to burn, resulting in an increase in emissions "inconsistent with the emissions reductions goals of the CAA, and of section 112 in particular." *Id.*

But unlike natural gas, which is generally stored as a commodity when not consumed, coke oven gas must be flared as a waste gas to ensure a safe environment if not immediately usable at a facility. As a result, creating incentives which cause operators of coke oven gas-fired units to fuel-switch (even to natural gas) would result in significant net emissions increases. That is because the facility would necessarily combust both the coke oven gas (at a flare) and the additional fossil fuel necessary to generate sufficient heat for its operations. Simply put, any standard that creates a disincentive to recover energy from process gases is bad for the environment and thus contrary to the goals of the CAA. Extending work practice tune-up standards to coke oven gas or process gas-fired boilers will ensure that there is no environmentally detrimental incentive to displace coke oven gas or process gas with natural gas or other fuels in the boiler and flare those recoverable energy sources.

**If EPA Decides to Impose Numerical Emission Limits for Gas 2 Fuels, EPA Should Develop a Separate Subcategory for Coke Oven Gas-Fired Units**

EPA has proposed the Gas 2 subcategory to encompass all gaseous fuels that are not natural gas or refinery gas. This catch-all subcategory includes landfill gas, coke oven gas, coal-derived gas, biogas, and other process gases. EPA offers no justification for combining these disparate gases into a single subcategory but it may have been driven by a lack of data. With just five sources in the Gas 2 subcategory with dioxin-furan data and just eight sources with data for Hg and HCl, EPA had tied its own hands by not collecting sufficient data to properly distinguish between fuels with significantly different chemical compositions, heating values, and combustion characteristics. EPA's decision to lump these Gas 2 sources together based on what they are not (*e.g.*, because they are not burning natural or refinery gas) is arbitrary and unlawful.

Gas 2 fuels are not interchangeable. These gaseous fuels are combusted at or near their point of generation and used to reduce reliance on fossil fuels. Therefore, a Gas 2 source cannot decide to burn landfill gas to help meet the Hg emission standards if they are not in the vicinity of a landfill. Similarly, coke oven gas is only available in the vicinity of coke batteries. Thus, most of the 199 Gas 2 sources cannot use coke oven gas to help meet the dioxin emission limits. Nor does it make environmental or economic sense to displace process gases with natural gas because flammable process gases must be combusted to meet health and safety requirements. Flaring process gases and burning natural gas to reduce emissions at the boiler increases facility-wide emissions, decreases energy independence, and wastes opportunities for energy efficiency. Process gas-fired sources are not candidates for fuel switching.

EPA must, as a result, evaluate and understand the emission characteristics of each process gas fuel to determine if its Gas 2 subcategory is properly defined as a reasonable aggregation of similar sources. EPA has proposed an arbitrary aggregation of dissimilar fuels in the Gas 2 subcategory, which would result in emission limits that are not achievable when burning some process gases even when implementing all available control measures. This should be a strong signal that further subcategorization is warranted prior to the promulgation of the final Boiler MACT rule. If EPA will be setting numeric emission limits for coke oven gas-fired boilers, then these units need a separate subcategory because they have no pathway to attain emission limits established by dissimilar landfill gas and biogas-fired units.

EPA's current database is insufficient to understand emissions from coke oven gas-fired sources. Of the three units identified in the EPA database as coke oven gas-fired, two have been confirmed as burning petroleum coke, a solid fuel, and not coke oven gas. These data must be excluded from any gaseous fuel analysis. The only remaining emissions data in the EPA dataset for coke oven gas-fired units comes from a source test snapshot of a recovery coke plant in West Virginia that uses a desulfurization system. This limited data from a single source cannot adequately represent the variability inherent in the coke oven gas-fired sources identified by EPA within the Gas 2 subcategory. However, the data can, and do, indicate significant differences between coke oven gas emissions and other Gas 2 process gases.[6]

To gain a better understanding of the potential risk faced by coke oven gas-fired units under the broad Gas 2 subcategory proposed by EPA, an AISI member company conducted stack tests on four coke oven gas-fired boilers in July 2010. The test results confirm that the proposed Gas 2 emission limits for HCl, Hg, and CO are not achievable for these coke oven gas-fired boilers using commercially available emission control technologies. The tests were performed on four identical tangentially-fired industrial boilers. Each boiler has a rated heat input capacity of 650 MMBTU/hour and fires only gaseous fuels, comprised of a mixture of coke oven gas and blast furnace gas with supplementary natural gas, that are supplied to the boilers from common headers for each fuel. Typical fuel gas analyses are provided in Table 1. The boilers operated at 73% to 87% (average 83%) of design heat input capacity during the tests. The average

[6] For a discussion of these differences, we direct you to the comments of the American Petroleum Institute and the National Petrochemical Refiners Association, which reveal significant differences in the emission characteristics among the Gas 2 fuels.

contribution of each fuel to total heat input during the tests was 50% coke oven gas, 39% blast furnace gas and 11% natural gas (Table 2).

The test program included the following measurements in each boiler stack:

- Group A:
  - CO by EPA Method 10;
  - Dioxins and furans by EPA Method 23;
  - HCl and filterable non-sulfuric acid PM by EPA Method 26A, combined with EPA Method 5B;

- Group B:
  - Hg and filterable non-sulfuric acid PM by EPA Methods 29 and 101A, combined with EPA Method 5B (modified);

- Stack gas flow rate by EPA Method 2 (all tests); and

- Oxygen, carbon dioxide and moisture concentration by EPA Methods 3A and 4 (all tests).

Three 4-hour test runs were performed on each of the four boilers. Group A and Group B tests were not conducted simultaneously. Tests were performed at approximately the same time of day and under comparable operating conditions. The test methods for CO, Hg, HCl and dioxins/furans are among those specified by EPA for tests conducted under the ICR for this rule and in Table 5 to Subpart DDDDD of Part 63 - Performance Testing Requirements of the proposed rule.[7]

Method 5B was selected for filterable PM because it is believed to be a superior surrogate for non-mercury metallic HAPs when sulfuric acid may be present, as discussed elsewhere in these comments. Sulfur dioxide ($SO_2$) concentrations in the exhaust gas indicate that sulfuric acid may be present at concentrations on the order of 5-7 ppmv, which represents a potentially large fraction of the proposed filterable PM limit (on a lb/MMBTU basis). Method 5B is designed to mitigate the effect of sulfuric acid on the filterable PM results, which allows for a more accurate surrogate for non-mercury metallic HAP. For the Method 29 and Method 101A tests, filterable PM samples were collected with the probe and filter temperature at 160°C as specified in Method 5B, but the laboratory analysis was modified by drying the samples in a desiccator at room temperature as specified in Methods 29 and 101A rather than in an oven at 160°C as specified in Method 5B, so that Hg was preserved in these samples. For the Method 26A tests, Method 5B was performed normally.

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[7] The test method for dioxins/furans was left blank in Table 5 of the proposed rule. EPA should correct this oversight in the final rule. We assume that Method 23 is the intended method for these compounds based on the preamble discussion at 75 Fed. Reg. 32013.

The test results show highly variable CO emissions with an average concentration 28 times higher than the proposed limit. Also, HCl and Hg values exceed the proposed limits by more than an order of magnitude (Table 3 and Figure 1) rendering them unachievable. Highly variable CO results among the four identical units were not unexpected due to the presence of blast furnace gas in the fuel mix,[8] the nature of these low BTU fuels, and normal variations in boiler operations even at a relatively constant total heat input near design capacity. These short duration tests cannot capture the full range of normal operating conditions that might be experienced over several years. However, they are important indications that coke oven gas-fired units are significantly different from other Gas 2 units and that further data and analysis are needed before setting numeric emission limits for coke oven gas-fired units.

The levels of HCl, Hg, and CO exceed the proposed Gas 2 limits by such a large margin that available emission control measures would be insufficient to achieve the proposed Gas 2 limits. If optimistic assumptions for control efficiency are applied to the uncontrolled levels measured in these tests, it is clear that the Gas 2 emission limits cannot be reliably achieved (Table 4). Even assuming 99% HCl removal, the proposed Gas 2 limits could not be achieved. This control efficiency is very optimistic given the low inlet HCl concentrations and the challenges associated with optimizing scrubber performance when burning variable mixed gas fuels. Similarly, activated carbon injection has been demonstrated to be perhaps 70 to 90+% effective in reducing Hg emissions at much higher inlet Hg concentrations present in waste incinerators and coal-fired boilers. Hg reduction will be less effective at very low inlet concentrations. Conservatively assuming 80% control efficiency, controlled Hg levels will be 5 to 10 times higher than the proposed Gas 2 limits. CO reduction efficiency by oxidation catalysts can be quite effective in gas turbine applications; however, boiler stack gas temperatures are much lower than catalyst temperatures in those applications, and oxidation catalyst efficiency decreases with decreasing temperature. Even assuming an optimistic CO reduction efficiency of 90%, it would not be possible to achieve the Gas 2 emission limits in 3 of the 4 cases.

Based on this analysis, it is technically infeasible for coke oven gas-fired boilers to achieve the proposed Gas 2 emission limits. Therefore, in the event that numerical emission limits are imposed on coke oven gas-fired units over our prior noted objections, we recommend that EPA develop a separate subcategory for coke oven gas-fired units to accommodate their unique chemical composition and emission profile.

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[8] Blast Furnace Gas contains large amounts of carbon monoxide and no organic HAP, thus the presence of CO in the exhaust gas from BFG fuel mixtures may not be an indication of the presence of organic HAP. The highest CO was observed during tests on Boiler 12, which is attributed to the higher relative contribution of blast furnace gas at that boiler.

**The Definition of Gas-Fired Boilers Should be Amended**

The definition of gas-fired boilers includes those units burning gaseous fuels, which by further definition includes process gases (*e.g.*, coke oven gas, blast furnace gas, or basic furnace off-gas). However, the definition of gas-fired boiler is qualified by stating that gaseous fuels cannot be combined with any liquid fuel except during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuels. Without clarification of that definition, the exemption for gas fired boilers is potentially negated.

While coke oven gas boilers are primarily designed to burn coke oven gas, usually with natural gas as a back-up fuel, they are sometimes supplemented with liquid fuels when the supply of coke oven gas from the coke oven process is interrupted due to operational difficulties or reduced operations necessitated by business conditions or when steam demands elsewhere in the plant that rely on steam from those boilers cannot be met by the available coke oven gas supply to the boilers. Similar circumstances can arise with blast furnace gas-fired boilers, *e.g.*, during blast furnace relines, tuyere changes, or other temporary outages. It is not clear from the definition of gas-fired boiler whether the terms gas curtailment and gas supply emergencies pertain to commercial natural gas supplies or can be interpreted to include occasions of curtailment and supply deficiencies from the process supplying the gas to the boiler. In the absence of clarifying language in the definition, the occasional use of liquid fuel would place these boilers (as well as any units using any liquid fuel, except in the stated circumstances) into a category that requires stringent emission limits, the installation of costly emission control equipment, and testing, monitoring and recordkeeping obligations.

If the qualification of liquid fuel usage remains in the definition of gas-fired boiler, we suggest adding further clarifying language that is contained in the definition of a waste heat boiler in the Proposed Rule. As noted above, waste heat boilers are exempt from the rule. The waste heat boiler definition in the Proposed Rule is limited to units designed to use no more than 50% of the total heat input capacity of the unit with supplemental burners. We believe that the environmental and energy conservation benefits of using coke oven gas are comparable to the use of waste heat or blast furnace gas, both exempted under the Proposed Rule, and that the same provisions for using supplemental fuels should apply to units intended to utilize coke oven gas. Accordingly, applying the same rationale, we urge EPA to modify the gas-fired boiler exemption to include those units designed to use supplemental fuels up to 50% of the total heat input capacity of the unit.

In addition, AISI requests that EPA provide clarification that boilers firing liquefied petroleum gas (LPG) or propane-derived synthetic natural gas (SNG) as a backup fuel are considered a gas-fired boilers. We note that EPA proposes to incorporate ASTM D183503a to define "natural gas" for purposes of this regulation. It is important that any standard incorporated by the regulation be broad enough to encompass the use of propane (a constituent of LPG) as natural gas and not just mixtures. Most LPG mixtures include butane, which reduces the effectiveness of LPG at low temperatures, causing many facilities to substitute propane. Propane (and/or LPG) is mixed with air to create SNG, which should be specifically allowed to be considered as natural gas for purposes of this rule. LPG-based SNG is often used for emergency backup and EPA should make this point explicit in the final rule.

Finally, we request clarification that a boiler combusting landfill gas (or similar gaseous fuels derived from landfills or monofills) is considered a gas-fired boiler and not in the biomass category. AISI considers these fuels to fall under the definition of biogases, which are included in the definition of gaseous fuels, but we are aware that EPA has taken the position that gas derived from landfills is "biomass" under other rules. We seek clarification that for purposes of this rule it is not the agency's intent to regulate boiler use of landfill or monofill gas, even if derived in whole or part from materials that might be defined as biomass.

## The Metal Process Furnace Subcategory Should Include Furnaces That Combust Process Gases

The steel industry employs numerous metal process furnaces, including reheat furnaces, annealing furnaces, and heat treating operations. Some of these are direct-fired and are not covered by the rule, but others are indirect fired units that would classify them as process heaters. AISI supports the separate classification of "metal process furnaces," which EPA found to be a "class of natural gas-fired process heaters that are designed and operated differently compared to typical process heaters." *Id.* at 32017. As explained in the Proposed Rule:

> A review of information gathered on process heaters used in the metal processing industries shows that these process heaters typically are designed with multiple burners that fire into individual combustion chambers. These individual burners are operated to cycle on and off to maintain the proper temperatures throughout the various zones of the process heater. Thus, due to their design, these process heaters rarely operate in a steady-state condition due to burners constantly starting up and shutting down. This results in emissions characteristics different from the process heaters used in other industries.[9]

[9] *Id.*

That passage correctly identifies the technological and operational issues that justify creation of a metal process heaters subcategory. However, the Proposed Rule further circumscribes that group by defining it to include only units that combust natural gas. *Id.* ("[t]he process heaters used in metal processing are natural gas-fired and include annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, and heat treat furnaces"). While many metal process furnaces do use natural gas, others recycle (or can be used to efficiently recycle) process gas, such as coke oven gas, in order to reduce the amount of additional natural gas needed to operate these units.

The type of gas combusted in a given metal process heater has nothing to do with the technical and operational distinctions that render them unique, including the fact that they are designed with multiple burners in a single unit and rarely operate in a steady-state condition. Rather, those same findings apply equally to all metal process heaters combusting any gaseous fuel. As such, there is no legitimate basis for limiting this subcategory to natural gas-fired units and EPA should redefine this subcategory to include furnaces combusting any gaseous fuel.

**<u>All Metal Process Furnaces Should Be Subject to Work Practices</u>**

The Proposed Rule provides work practice standards for the metal process furnaces subcategory. *Id.* at 32012. Section 112(h)(1) of the CAA authorizes the promulgation of work practices in lieu of emission limits "if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant or pollutants." EPA properly concluded that emission standards are not feasible for metal process heaters for two reasons. First, imposing emission limitations on these units would be economically impracticable - particularly in contrast to the very limited emissions reductions that could be achieved. 75 FR at 32025. Second, EPA noted that proposing emission standards for metal process heaters would run contrary to §112's goals because they "would result in an overall increase in HAP emissions" by "providing a disincentive for switching to gas as a control technique (and a pollution prevention technique)...." *Id.*

As detailed in the preceding section, these concepts are equally applicable to all gaseous fuels. Indeed, any standards that threaten to penalize process gas recycling would pose a grave environmental threat. Process gasses are, by definition, the product of another process. If these gases are not reclaimed for their heat content (in place of natural gas or another fossil fuel), they are typically flared. Given the exorbitant costs EPA identified above for controlling emissions from metal process furnaces, metal process furnaces currently burning process gas in lieu of natural gas will switch to natural gas exclusively and flare the process gas, resulting in "an overall increase in HAP emissions." Further, greenhouse gases and criteria pollutant emissions would also increase as the process gases are flared while nearby boilers also combust virgin fossil fuels. To avoid that untoward result, work practices should apply equally to all metal process furnaces.[10]

**EPA Should Expand the Category of "Metal Process Furnace"**

AISI requests that EPA revise the definition of metal process furnace to include the phrase "includes, but is not limited to" to acknowledge the fact that there may be other furnaces that should be excluded. Examples of such furnaces, in addition to annealing, preheat, reheat, aging and heat treat furnaces, include:

- Stress relief furnaces, which are similar to aging and heat treat furnaces in that they are used to heat and cool metal to eliminate stresses from forging and similar activities.
- Galvanizing/galvanneal furnaces, which are similar to annealing furnaces in purpose and operation, but operate on a continuous (strip) rather than batch (coil) basis. Like annealing furnaces, these units fire sporadically as necessary to achieve an annealed consistency in the metal.

Alternatively, we request that EPA specifically add both of these units to the list of "metal process furnace" examples included in proposed §63.7575.

## GENERAL COMMENTS

**MACT Floors Must Be Based on the Overall Performance of Actual Sources - Not on a Pollutant-by-Pollutant Basis**

The proposed MACT standards for industrial boilers and process heaters are based on pollutant-by-pollutant analyses that rely on a different set of best performing sources for each HAP. *See, e.g.,* 75 FR at 32019 ("For each pollutant, we calculated the MACT floor for a subcategory of sources by ranking all the available emissions data from units within the subcategory from lowest emissions to highest emissions, and then taking the numerical average of the test results from the best performing (lowest emitting) 12 percent of sources."). In other words, EPA has "cherry picked" the best data in setting each standard, without regard for the sources from which the data come. The result is a set of standards that reflect the performance of a hypothetical set of best

[10] Even if process gas-fired metal process furnaces are left in the Gas 2 subcategory, EPA has the authority to promulgate work practices in lieu of emission standards for them. Given the costs of compliance with emission standards, as well as the reduction in emissions created by allowing metal process furnaces to burn process gas instead of natural gas, work practices should be adopted for these units regardless of their subcategorization.

performing sources that simultaneously achieve the greatest emission reductions for each and every HAP rather than the actual performance of real sources. This approach is contrary to the language of §112.

The Clean Air Act (CAA) directs EPA to set standards based on the overall performance of sources. Sections 112(d)(1), (2), and (3) specify that emissions standards must be established based on the performance of "sources" in the category or subcategory and that EPA's discretion in setting standards for such units is limited to distinguishing among classes, types, and sizes of sources. These provisions make clear that standards must be based on actual sources, and cannot be the product of pollutant-by-pollutant parsing that results in a set of composite standards that do not necessarily reflect the overall performance of any actual source. Congress provided express limits on EPA's authority to parse units and sources for purposes of setting standards under §112 and that express authority does not allow EPA to "distinguish" units and sources by individual pollutant as proposed in this rule. *Sierra Club v. EPA*, 551 F.3d 1019, 1028 (D.C. Cir. 2008).

Moreover, an analysis of EPA's emissions database shows that, in fact, the proposed standards for Gas 2 units do not reflect the performance of any actual sources. In the Gas 2 subcategory, not a single source is represented in what EPA has determined is the top 12% of sources for each and every pollutant. Furthermore, the few sources represented in the top 12% for multiple pollutants have actual emission test data demonstrating their inability to meet emission limits established for other pollutants. For example, Shell Chemical - Geismar possesses a unit that was included in the top 12% of performing units for HCl, PM, and CO, but dioxin tests on this unit demonstrate that it will not meet dioxin/furan limits. Likewise, BMW Manufacturing Company has a unit included in the top 12% of performing units for dioxin/furan and Hg, but test results demonstrate that this unit will not meet proposed HCl or CO limits.

EPA's proposed emission limits provide all sources that are unable to meet all emission limits simultaneously (which is all sources) with only two options - operate in violation of at least one emission limit at all times or shut down. This is an untenable position and contradicts EPA's duty to set emission limits that are achievable. In the Brick MACT decision, Judge Williams discussed EPA's obligation to impose MACT floors that are reasonable and achievable:

> What if meeting the "floors" is extremely or even prohibitively costly for particular plants because of conditions specific to those plants (*e.g.*, adoption of the necessary technology requires very costly retrofitting, or the required technology cannot, given local inputs whose use is essential, achieve the "floor")? For these plants, it would seem that what has been "achieved" under §112(d)(3) would not be "achievable" under §112(d)(2) in light of the latter's mandate to EPA to consider here.... In other words,

> as applied to some sources, the floor compelled by the statutory language appears to be more stringent than "beyond-the-floor."
>
> If this were all, we might be talking of a statute whose literal words produced a result so "demonstrably at odds with the intentions of its drafters" as to justify judicial surgery....
>
> Happily §112 is not such a statute.

*Sierra Club v. EPA*, 479 F.3d 875, 884-85 (D.C. Cir. 2007). Thus, EPA has not only the authority but also the obligation to create MACT floors that are achievable in practice.

**MACT Floors for Existing Sources Must be Based on a Group of Similar Sources**

The Proposed Rule explains that "the proposed new and existing source MACT floors are almost identical [in certain instances] because the best performing 12 percent of existing units (for which we have emissions information) is only one or two sources." 75 FR at 32022. EPA further explains that "[t]he reason we look to the best performing 12 percent of sources, even though we have data on fewer than 5 sources, is that these subcategories consist of 30 or more units." *Id.* That approach is based on the conclusion that a "plain reading" of §112(d)(3)(A) requires use of the top 12% of sources for which EPA has emissions data for source categories with 30 or more sources, even where the available emissions data are sharply limited.

At the same time, EPA failed to collect adequate sampling data from Gas 2 units. As detailed in Appendix H-1 of EPA's April 2010 MACT floor analysis, the Gas 2 subcategory consists of at least 199 units. Despite that large pool of units, EPA reportedly only possesses: (1) PM data from thirteen Gas 2 units, (2) Hg and HCl data from eight Gas 2 units, and (3) dioxin/furan data from five Gas 2 units. EPA's proposed reading of §112(d)(3)(A) and this striking lack of data combine to create untenable MACT floor limits based on insufficient numbers of sources. For example, the proposed Gas 2 MACT floor for PM was established based on just two units and the Gas22 MACT floors for Hg, HCl, and both dioxin/furan parameters were set by reference to one single source. *See id.* at Appendix C-1.

That approach contradicts the primary structure of §112(d). When drafting the 1990 Amendments to the CAA, Congress carefully established distinct approaches for establishing the MACT floors that would apply to existing and new sources. For existing sources, Congress established two alternate approaches in §§112(d)(3)(A) and (B). Where there are "30 or more sources" in a subcategory, §112(d)(3)(A) instructs EPA to select "the average emission limitation achieved by the best performing 12 percent of the existing sources." Similarly, where there are "fewer than 30 sources" in a subcategory, §112(d)(3)(B) requires use of "the average emission limitation achieved by the best performing 5 sources...." Both of these provisions were designed to ensure that a group of existing sources are used to establish the emissions limits for existing sources.

In contrast, §112(d)(3) specifies that the MACT floor "for new sources in a category or subcategory shall not be less stringent than the emission control that is achieved in practice by the *best controlled similar source*...." (Emphasis added) Thus, new source limits are to be set by a single source while existing source limits were to be set by reference to a group of representative peers.

The Proposed Rule would contradict that clean statutory line by treating existing sources as if they were new sources. As §112(d)(3)'s plain language establishes, Congress intended existing units to be subject to MACT standards already proven achievable by a group of their peers - not a lone unit due to the lack of available data.[11] That approach also makes good common sense since existing units cannot be designed from the ground up like new units, but are necessarily subject to the physical and technological limitations associated with their current design. Thus, under no circumstance should any MACT floor for existing sources be set by reference to just one or two units.

Apparently recognizing these concerns, the Proposed Rule solicits comment on whether EPA "should consider reading the intent of Congress to allow us to consider five sources rather than just one or two." *Id.* EPA suggests that, by requiring data from 5 sources to be used for source categories with fewer than 30 sources, Congress was concerned that the floor should be determined using "a minimum quantum of data." EPA posits that, if 5 is the "minimum quantum" for source categories with fewer than 30 sources, then it is natural to conclude that the "minimum quantum" should be no less than 5 sources for categories with 30 or more sources. *Id.*

That alternate approach is far more consistent with §112(d) and Congress' plain intent. It is also well within EPA's discretion to adopt this more consistent approach. The word "sources" as used in the last clause of §§112(d)(3)(A) and (B) to describe the size of the subcategory at issue does not specify whether it refers to "sources" for which data exist or the total number of sources in the subcategory. However, the word "sources" in the earlier facets of those sections clearly refers to the sources for which EPA has emissions information. Thus, it is reasonable to conclude that Congress intended the word "sources" to have a consistent meaning within these subsections and that the reference "30 or more sources" at the end of §112(d)(3)(A) and "fewer than 30 sources" at the end of §112(d)(3)(B) reasonably means sources for which EPA has emissions information. That interpretation allows EPA to read the statute such that

[11] As noted above, it was incumbent on EPA to collect adequate data to adequately characterize all subcategories for which it plans to establish numeric MACT floors.

Congress' chosen line between new and existing source-setting methodology is not blurred.[12]

Alternately, EPA's use of at least 5 sources could also be justified under the "absurd results" doctrine. Congress clearly expected enough emissions information to be available for larger source categories to generally cause more than 5 sources to constitute the top 12%. It makes no sense for Congress to specify a minimum number of sources for source categories with few sources, but then to create a rule that would allow for standards to be set using data from fewer than 5 sources in larger source categories. Using no less than 5 sources would give effect to the clear intention of Congress.

**EPA Inappropriately Relies on Emissions Data from the "Best of the Best" in Determining the Existing Source MACT Floors.**

In one fashion or another, EPA has been working on the Boiler MACT standards for better than 15 years and has known that it needs to set these standards since the 1990 Clean Air Act Amendments were enacted almost 20 years ago. Despite this long run-up to the proposed rule, the agency has shockingly little data available to set the existing source standards. Tables 2 and 3 in the preamble tell the tale.

Using biomass-fired boilers as an example, Table 2 shows that the subcategory includes 420 sources, yet EPA has emissions testing data on 192 units for PM, 91 units for Hg, and 92 units for HCl - 46%, 22%, and 22% data availability, respectively. The numbers are far worse for many other pollutants and subcategories. The relative lack of data is a fundamental problem because EPA construes the statute as requiring it to set existing source MACT floors based on either the top performing 12% of sources for which it has data for the larger source categories and subcategories. Less data means the pool from which the top 12% is drawn is smaller and, therefore, the actual number of sources used to determine the MACT floor is smaller.

While it is true that the statute allows EPA to determine the MACT floor based on sources "for which the Administrator has emissions information," this provision does not excuse EPA from using its resources and legal authority to obtain as much

[12] *See, e.g., United Savings Ass'n of Tex. v. Timbers of Inwood Forest Assoc., Ltd.*, 484 U.S. 365 (1988) (rejecting a "reasonable" meaning of a statutory term and stating that "[s]tatutory construction ... is a holistic endeavor. A provision that may seem ambiguous in isolation is often clarified by the remainder of the statutory scheme - because the same terminology is used elsewhere in a context that makes its meaning clear ... or because only one of the permissible meanings produces a substantive effect that is compatible with the rest of the law." (citations omitted)); *S. Cal. Edison Co. v. FERC*, 195 F.3d 17 (D.C. Cir. 1999) (striking down FERC's statutory interpretation that rendered statutory text meaningless in favor of an alternate interpretation without this effect, noting that "statutory words are ... designed to carry out the statutory purposes").

information as it reasonably can prior to setting MACT standards. In this case, EPA has had 15 to 20 years to gather the needed information. The fact that, at this point, data on only a small subset of sources in each subcategory is available represents an abdication of EPA's responsibility and renders the resulting standards arbitrary and capricious.

This problem is further exacerbated by the fact that the bulk of the information on which EPA's relied in developing the proposed standards was collected by way of a §114 information request that required testing of specified units for specified pollutants. The record reveals that EPA intentionally directed the information request to units that it had reason to believe were the better performing units in each subcategory.

During the Phase I Boiler MACT data collection effort, EPA requested and received emissions data from most of the potentially affected sources across all of the subcategories for PM, CO, nitrogen oxides, and many HAPs. After sifting the Phase I data, EPA developed a Phase II plan for collecting additional data. During this second round, however, EPA targeted only those sources whose data EPA determined it would need to set the MACT floor.[13] In this way, EPA artificially limited the pool of data from which it drew its top 12% best performing sources. The result is fatally arbitrary because EPA's sampling approach for Phase II created a dataset that is not representative of sources for which the data is being used to infer emissions.

Instead of using emissions data from the "best of the best," EPA should simply use emissions data from the "best" units in each subcategory. In other words, EPA should determine how many units constitute the top 12% in each subcategory (or top 5 in subcategories with fewer than 30 sources) and then use emissions data from this number of units (or as many of these units for which emissions data are available) in determining the MACT floor and MACT standard. This approach is warranted because the Phase I ICR data allowed EPA to reliably select the top performers in each subcategory for purposes of collecting the Phase II information. As a result, EPA has sufficient "emissions information" for each subcategory to reasonably select the top performers on which the MACT floor and MACT standard should be based.

**<u>The Proposed Rule Fails to Adequately Account for Emissions Variability Reasonably Expected of the Top Performing Sources</u>**

EPA has improperly developed a CO standard that boilers must meet at all times based on 3-run stack tests that fail to properly characterize the highly variable nature of CO emissions in solid fueled boilers. CO emissions from boilers can be highly variable, especially when fuel mix and load change. Facilities are typically required to conduct stack tests at least 90% of full load during normal operating conditions. Therefore, a CO stack test is going to represent the best operation of any boiler. EPA has used only 3-

[13] 75 FR 32010

run stack test data, which represents only a small and unrepresentative snapshot in time captured during the best operating conditions, to set emission limits for a pollutant that is highly variable.

In fact, as demonstrated in the comments below, further analysis of CO CEMS data included in EPA's database for top performing units in each of the solid fuel subcategories reveals that even the top performing sources would not be able to meet the proposed CO standards that are based on the performance of those very units. Further analysis of record data also clearly shows that EPA is mistaken in its suggestion that CO emissions do not vary with load. In fact, to adequately accommodate expected CO emissions variability with load, the 2004 Industrial Boiler MACT rule did not require CO CEMS data obtained at less than 50% of maximum load to be included in the 30-day CO average. EPA's proposal not to accommodate load variability is not supported by the record and inexplicable as a technical matter.

EPA makes a similar mistake with regard to its proposal not to set a separate standard for periods of startup, shutdown, and malfunction. On the one hand, EPA asserts that "[t]he standards we are proposing are daily or monthly averages ... [t]hus, we are not establishing separate emission standards for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards."[14] On the other hand, EPA uses short-term performance test results to set the standards rather than the results of long-term CEMS monitoring. As a result, the emissions data on which the standards are based do not, in fact, reflect or adequately accommodate emissions from periods of startup, shutdown, or malfunction.

More generally, EPA proposes to use the 99% upper predictive limit (UPL) to accommodate and reflect variability in the operation of the best performers in calculating the MACT floor. The use of the 99% UPL calculated on only a small number of sources in a subcategory does not adequately capture variability or serve to predict the MACT floor level achievable by the top performers. In essence, the agency is using this statistical method in an attempt to overcome the limited amount of emissions data available for top performers. However, this statistical approach cannot overcome the fact that the data are not representative of the entire population of boilers in each subcategory and that the available data do not reflect the true variability of the top performing sources.

In the final rule, EPA must use data to set the standard that are consistent with the form of the standard. As compliance with the CO standard is to be measured at all times using CO CEMS for units of 100 MMBTU/hr and greater and the averaging time is 30 days, EPA should use 30-day CEMS data from affected boilers to establish the appropriate MACT floors and not 3-run stack test data. To assure that startup,

[14] 75 FR 32013

shutdown, and malfunction are appropriately accommodated, EPA must either assure that the data on which the standard is based include representative data from such periods or, alternatively, set a separate work practice standard to properly accommodate startup, shutdown, and malfunction. Lastly, instead of using the UPL, EPA should use the upper tolerance limit (UTL), which is meant for use in situations where the available data does not represent the entire population. In addition, since the proposed 99% confidence interval is applied to all 5 HAPs, the combined probability of achieving the set of limits drops to 95%, which is inappropriately low when facilities must be in compliance 100% of the time. EPA therefore should use a 99.9% confidence limit for all standards.

**The Emissions Database Includes Numerous Fundamental Flaws That Compromise the MACT floor Analysis Based on These Data**

Given the limited comment period that has been provided on the Proposed Rule, it simply has not been possible to conduct a thorough data quality assessment on EPA's entire emissions data base. EPA's failure to provide adequate time for an appropriate assessment of the data violates the agency's obligation to provide a full and fair opportunity for public comment on the proposed rule. Within these severe time constraints, industry representatives conducted a spot check of 100 stack test reports and associated information from top performers in order to assess the quality of the data the agency relied upon in calculating the MACT floors that underlie the proposed rule.

This spot check revealed numerous data errors - many of which, if corrected, would have a material impact on the stringency of EPA's calculated MACT floors and associated proposed standards. To name just a few, there was: (1) widespread inconsistency in the data reported under the Phase I and Phase II ICRs, such as entirely different methods of determining and reporting "non detects"; (2) inconsistent reporting of dioxin/furan emissions testing results; (3) inconsistent and incompatible PM emissions testing methods; and (4) mischaracterization of boiler types, such as including a coal-fired boiler in the biomass subcategory. The number and magnitude of the errors provide clear evidence that the database is fundamentally flawed and that any standard derived from the database does not have adequate factual support.

To resolve this problem, EPA must conduct a thorough review of the database, correct or eliminate the flawed data, recalculate the MACT floors and associated proposed standards, and provide a new opportunity for public comments (including sufficient time for commenters to conduct their own comprehensive review of the data).

Along the same lines, the fact that EPA has not finalized the waste definition rule[15] prior to asking for public comment on the Proposed Rule creates a fundamental procedural problem that is not solved by EPA's alternative MACT proposal.[16] While the waste definition proposal does set forth two basic approaches to distinguishing waste from fuel, the proposal also asks for comments on numerous specific elements of each of these approaches.[17] As a result, the proposal sets out a continuum of possible final rules rather than two distinctly different possibilities. This means that commenters on the proposed MACT have no way of knowing what population of units will qualify as boilers upon promulgation of the waste rule and, therefore, cannot conduct a meaningful review of the Industrial Boiler MACT emissions database with regard to the units that ultimately will be used to determine the MACT floors and MACT standards.

The inability to reasonably ascertain which units will actually be used in setting the final Industrial Boiler MACT standards prevents commenters from developing meaningful comments on the emissions database and on EPA's manipulation of the data that ultimately will be used to set the standard. In short, EPA's proposed rule effectively requires commenters to guess what data EPA will eventually use to set the standard. This violates EPA's duty to provide a full and fair opportunity to develop and submit comments on the proposal. This problem can only be cured by promulgating the waste rule and then proposing industrial boiler standards based on the units that are then known to be industrial boilers.

**The MACT Floors Must be Set Based on All Available "Emissions Information," Not Just Sampling Data**

Section 112(d)(3)(A) instructs EPA to set the MACT floor for existing sources in categories or subcategories with 30 or more sources at the "average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has *emissions information*) ..." (emphasis added). Section 112(d)(3)(B) imposes that same "emissions information" threshold for smaller subcategories. In the Proposed Rule, EPA interprets these provisions as requiring the MACT floor to be calculated using data from the top 12% of sources for which actual emissions testing data is available. That narrow approach does not properly account for the breadth of the statutory language, which reaches sources for which any "emissions information" is

[15] The waste definition rule is proposed at 75 FR 31844 (June 4, 2010).

[16] *See*, 75 FR 32035 ("Alternative Standard for Consideration").

[17] *See, e.g., id.* at 31873 ("EPA is proposing that non-hazardous secondary materials used as fuels in combustion units that remain within the control of the generator and that meet legitimacy criteria specified in section VII.D.6 would not be solid waste ....Nevertheless, EPA is seeking comment on whether such secondary materials should be considered solid wastes and thus, be subject to the CAA section 129 requirements if combusted.")

available. The term "emissions information" unambiguously encompasses <u>any</u> information related to emissions - not just emissions rate information from performance testing or emissions monitoring devices.

There are plenty of industrial boilers and process heaters for which EPA does not have emissions testing data. That is particularly true for smaller units and those which combust process gases. However, EPA has at least some "emissions information" from virtually all of the sources involved. For example, EPA knows or can reasonably ascertain the volume and types of fuels and the emissions controls used by the vast majority of industrial boilers and process heaters in use today. EPA has developed emissions factors for various types of units based on this information and published them in AP-42. Sources are encouraged to rely on these emission factors to estimate emissions in the absence of actual test data. EPA too, then, should have used these emissions factors to estimate emissions for those units without emission testing data. This is "emissions information" that is readily available to EPA and should be included in selecting the group of sources that represent the top 12% of performers. Because at least some "emissions information" is available for virtually all sources in the category, EPA must calculate the MACT floor based on data from the best performing 12% of <u>all</u> sources in the category - not just those for which EPA has emission testing data.

**<u>We Support the Proposed Approach to Regulating Boilers in the "Gas 1" Subcategory and Believe That the Same Approach Should be Extended to Boilers and Units in the Biomass and "Gas 2" Subcategories</u>**

Instead of prescribing numeric HAP emissions limitations on boilers burning clean gas fuels (the "Gas 1" subcategory), EPA proposes to adopt work practices requiring an annual tune-up of the boiler. For units larger than 100 MMBTU/hr, EPA explains that "the capital costs estimated for installing controls on these boilers and process heaters to comply with MACT limits for the five HAP groups is over $14 billion."[18] EPA further explains that:

> [T]he need to employ the same emission control system as needed for the other fuel types would have the negative benefit of providing a disincentive for switching to gas as a control technique (and a pollution prevention technique) for boilers and process heaters in the other fuel subcategories. In addition, emission limits on gas-fired boilers and process heaters may have the negative benefit of providing an incentive for a facility to switch from gas (considered a "clean" fuel) to a "dirtier" but cheaper fuel (*i.e.*, coal). It would be inconsistent with the emissions

[18] 75 FR 32025.

reductions goals of the CAA, and of section 112 in particular, to adopt requirements that would result in an overall increase in HAP emissions.[19]

In short, EPA proposes that work practice standards are appropriate and justified for units in the Gas 1 subcategory out of concern for the cost of complying with numeric emissions limitations and based on the adverse policy incentives that would be created. We agree with EPA's assessment of the Gas 1 subcategory and support the proposed work practices.

We also note that there is very little difference between the emissions from the top performing sources in the Gas 2 subcategory as compared with the Gas 1 subcategory. As a result, in the alternative to further subcategorization of Gas 2 units as described below for coke oven gas-fired units, EPA would be justified in concluding that the Gas 1 and Gas 2 subcategories should be combined into a single gas-fired subcategory, which would be regulated by work practice standards for the reasons EPA explains in the preamble. At a minimum, units fired with process gases generated in chemical plants, pulp and paper plants, iron and steel plants, and similar operations should be included in the Gas 1 subcategory because the emissions data show very little difference in performance between units at these facilities and Gas 1 units.

While the agency is correct to establish work practice standards in lieu of numeric emissions limitations for natural gas-fired units, it need not do so under §112(h). Rather, EPA has independent authority to promulgate work practices as emission standards under CAA §302(k) as long as the work practices provide a continuous limit on emissions or are part of a set of regulations that provide a continuous limit on emissions. As required by CAA §112(d), EPA must promulgate "emission standards" for the control of hazardous air pollutants at major sources. Originally, these "emission standards" were found to be limited to only numeric emission limits. *See, e.g., Adamo Wrecking Co. v. U.S.*, 434 U.S. 275 (1978). However, in the 1990 Clean Air Act Amendments, Congress then expanded the definition of "emission standards" in §302(k) to expressly include work practices:

> The terms "emission limitation" and "emission standard" mean a requirement established by the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction, ***and any design, equipment, work practice or operational standard promulgated under this chapter.***

(Emphasis added.)

[19] *Id.*

As a result, the plain language of the CAA now authorizes the promulgation of work practices: (1) as direct emission standards under §302(k) and (2) in lieu of emission standards under CAA §112(h). While both of these sections authorize the implementation of "work practices," they are distinct provisions that serve different roles. As noted in the legislative history of the 1977 amendments to the CAA, the key to an emission standard under CAA §302(k) is that it applies continuously:

> By defining the terms "emission limitation," "emission standard," and "standard of performance," the committee has made clear that constant or continuous means of reducing emissions must be used to meet these requirements. By the same token, intermittent or supplemental controls or other temporary, periodic, or limited systems of control would not be permitted as a final means of compliance.

H.R. Rep. 95-294, at 92 (1977), as reprinted in 1977 U.S.C.C.A.N. 1077, 1170. As interpreted by the D.C. Circuit in *Sierra Club v. EPA*, 551 F.3d 1019, 1027 (D.C. Cir. 2008), "When sections 112 and 302(k) are read together ... Congress has required that there must be continuous section 112-compliant standards." CAA §112(h), on the other hand, includes no requirement for continuous regulation, allowing that "a standard may be relaxed 'if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a [HAP].'" *Id.* at 1028 (quoting 42 U.S.C. §7412(h)(1)).

EPA can therefore comply with CAA §112(d) by either: (1) promulgating CAA §112(d) emission standards that comply with the CAA requirement that "some section 112 standard apply continuously," under which Congress "did not authorize the Administrator to relax emission standards on a temporal basis" or (2) find that it is not feasible to prescribe or enforce a continuous emission standard under §112(d) and promulgate "work practice or operational standards instead" under §112(h). *Sierra Club*, 441 F.3d at 1028 (internal quotations omitted).

Moreover, this reading is consistent with §112(h)(4). That provision states, "Any standard promulgated under paragraph (1) shall be promulgated ***in terms of an emission standard*** whenever it is feasible to promulgate and enforce a standard in such terms." (Emphasis added.) In light of the D.C. Circuit's reasoning for distinguishing emission standards from 112(h) work practices, this provision is best read to require that, where EPA finds a continuously applicable work practice is not feasible under §112(h), it must promulgate "temporary, periodic, or limited systems of control" that resemble a continuous emission standard to the maximum extent possible. H.R. Rep. 95-294, at 92 (1977).[20]

[20] The D.C. Circuit's decision in *Sierra Club v. EPA*, 479 F.3d 875 (D.C. Cir. 2007), does not impact EPA's separate authority to issue direct work practice emissions standards as described in §302(k). Rather, that case focused on the breadth of EPA's authority under CAA §112(h), and only held that section

This dichotomy greatly simplifies the development of work practice standards for natural gas-fired units. Instead of turning to the alternate stop-gap provisions in §112(h) that apply when continuous emissions standards are not feasible, EPA can focus on the direct establishment of work practices that existing sources use to ensure continuous compliance under §§112(d) and 302(k). For example, if the top 12% of existing natural gas-fired boilers are using tune-ups to achieve their "best performing" status, then EPA has the authority to establish that protocol as a work practice-based emission standard. Tune-ups are an appropriate emission standard for these units because, if conducted with adequate frequency, they provide continuous reduction of the quantity and rate of HAP emissions from boilers by ensuring that they operate properly.

**In Any Event, a Work Practice Standard Should be Adopted for Dioxins/Furans in Lieu of Emission Standards**

The proposed dioxin/furan emission standards are so low and the detection limits of dioxin and furan isomers are so variable that many boilers are likely to exceed the proposed emission limits for dioxin/furans even though the tests show that all the isomers are present below the detection limits. Thus, imposing a dioxin/furan emissions limitation would be arbitrary and capricious because the method of demonstrating compliance would not reliably distinguish compliant boilers from noncompliant boilers.

In this situation, EPA has ample authority to prescribe a work practice standard instead of a numeric emissions limit. Section 112(h)(2)(B) authorizes EPA to establish work practice standards when "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." Such is the case for the proposed dioxin/furan standards - the proximity of the standard to the detection limit makes testing for compliance not technologically practicable, while the inability to accurately measure at the level of the proposed standard is economically impracticable because spending more money on the prescribed method will not resolve the inherent problem of setting the standard at the method detection limit. A work practice standard requiring good combustion practices is justified in this situation and would assure that dioxin/furan emissions are minimized.

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authorizes the establishment of work practices ***in lieu of an emission standard*** where "measuring emission levels is technologically or economically impracticable." *Id.* at 884. That holding says nothing about EPA's independent authority to establish work practices ***as direct emissions standards*** under CAA §112(d) and §302(k).

In any event, the §112 HAP list includes only the named compounds dibenzofuran and 1,3,7, 8 TCDD. Therefore, if EPA decides to adopt numeric standards, the standards must be specific to these compounds. EPA has no authority to regulate under §112 the generic chemical categories of "dioxins" and "furans."

## The Proposed Rule Should Not Mandate Energy Assessments

Energy conservation measures are laudable and a core part of everyday life in the steel industry. In fact, many steelmaking facilities already perform many of the investigations associated with an energy assessment as they have implemented the EnergyStar guidelines for energy management. Nevertheless, as explained throughout this section, EPA lacks the statutory authority to mandate facility-wide energy assessments for at least three reasons: (1) the energy assessment is not an "emission standard," (2) EPA may not reach beyond the defined source category to impose legal obligations, and (3) EPA has not demonstrated that the proposed energy assessment requirement is a cost-effective beyond-the-floor standard. Further, even if such a requirement was legally viable, there are serious implementation issues that would impair the viability and functionality of energy assessments in many instances.

Section 112 of the CAA does not authorize EPA to mandate that each facility housing a boiler or process heater perform an energy assessment. The Proposed Rule characterizes this energy assessment requirement as a beyond-the-floor regulation issued pursuant to the agency's authority under §112(d)(2). 75 FR at 32026. That provision, however, only authorizes EPA to promulgate "emission standards," which are carefully defined in CAA §302(k) to mean:

> A requirement ... which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction, and any design, equipment, work practice or operation standard promulgated under this chapter."

42 U.S.C. §7602(k). The proposed energy assessment requirement falls beyond that definition.

The proposed energy assessment would require an "in-depth energy study identifying all energy conservation measures appropriate for a facility given its operating parameters." 75 FR at 32026. Thus, that measure just mandates an evaluation of the facility's processes to "identify energy conservation measures ... that *can be* implemented to reduce the facility energy demand...." 75 FR at 32026 (emphasis added). That one-time identification of possible emission reductions and process changes will not "limit the quantity, rate or concentration of emissions of air pollutants," much less "on a continuous basis." Nor is the proposed energy assessment a "design, equipment, work practice or operation standard." As such, it falls beyond the defined concept of an "emission standard."

In fact, the U.S. Court of Appeals for the DC Circuit has held that a regulation imposing a general duty, without numerical emissions limits and without a mandatory plan for implementation, was not a free-standing emission limit and thus "not a section 112-compliant standard." *Sierra Club v. EPA*, 551 F.3d 1019, 1025-1028 (D.C. Cir. 2008). That same rationale applies here and confirms that the proposed energy assessment does not meet the threshold definition of an emission standard. As such, it is beyond EPA's authority under §112 to promulgate such a requirement.

In addition, EPA cannot impose requirements that reach beyond the defined source category. Section 112(c) establishes the scope of regulation under §112 by requiring EPA to publish "a list of all categories and subcategories of major sources and areas sources" for which "the Administrator shall establish emissions standards under subsection (d)." CAA §§112(c)(1) and (2), respectively. Pursuant to that requirement, EPA published a discrete list of major and area source categories. *See* 70 FR at 37824; *see also* 67 FR at 70428. Thus, that list of source categories sets both the maximum and minimum scope of EPA's regulatory authority to "establish emissions standards under subsection (d)."

The Proposed Rule explicitly states that the source categories affected by these rules are industrial, institutional, and commercial boilers and process heaters located at a major source. 75 FR at 32011 and 23049-50. Section 112 does not authorize EPA to promulgate regulations affecting sources beyond those specifically listed. Rather, as the legislative history confirms, "MACT standards shall be focused on *a specific portion* of a contiguous facility.... The entity covered by MACT would be defined at proposal of the standards." (emphasis added). A Legislative History of the Clean Air Act Amendments of 1990, 1990 CAA Leg. Hist. 731, 866. Thus, this rulemaking under CAA §112(d) only extends to the "specific portion" of the facilities identified in EPA's list under §112(c) and can go no further.

The proposed energy assessment requirement exceeds that focused statutory charge to develop emissions standards by reaching far beyond the "specific portion" of the facilities identified in EPA's §112(c) list. Specifically, the proposed energy assessment would require the inspector to "establish operating characteristics of the *facility*, energy system specifications, operating and maintenance procedures, and unusual operating constraints," "review ... available architectural and engineering plans, *facility* operation and maintenance procedures and logs, and fuel usage," and facilities containing major sources must develop a "*facility* energy management program" in accordance with the EnergyStar energy management program. 75 FR at 32068 (emphasis added). Additionally, the inspector is to "identify major energy consuming systems" and "list major energy conservation measures." *Id.* The inspector must then write up a comprehensive report summarizing his findings. *Id.* The only step properly limited to the regulated source category is the first one: "a visual inspection of the boiler system." *Id.* This step stands in stark contrast to the others, as it is the only one explicitly limited to the regulated source category. Save the first requirement of visually inspecting the boiler, the entire energy assessment requirement attempts to regulate operations beyond the defined source category.

EPA clearly lists the source categories subject to §112(d) and the Proposed Rule adheres to that same limitation by stating that it applies to industrial, commercial, and institutional boilers and process heaters. Nowhere is the source category defined as the facility that operates these units. Having defined the scope of this source category in its §112(c)(1) listing, EPA may not now reach beyond that category to impose obligations and limits. *See New Jersey v. EPA*, 517 F.3d 574, 583 (D.C. Cir. 2008) ("EPA may not construe [a] statute in a way that completely nullifies textually applicable provisions meant to limit its discretion.") (quoting *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 485 (2001)). As such, EPA may not require the conduct of facility-wide energy assessments or the implementation of findings made during such an assessment. Instead, §112 limits EPA to regulating the source itself, in this case boilers and process heaters.

In addition, the proposed energy assessment requirement is not cost-effective, particularly for complex steelmaking facilities. For beyond-the-floor controls, §112(d)(2) requires EPA to take "into consideration the cost of achieving ... emission reduction[s] and any non-air quality health and environmental impacts and energy requirements" which EPA "determines is achievable for new or existing sources in the category or subcategory to which such emission standard applies...." Thus, EPA must balance the cost of implementing pollution control measures with the magnitude of the reductions that will be achieved.

As an initial matter, the cost estimates in the Proposed Rule significantly underestimate the magnitude of conducting an energy assessment at large, complex manufacturing facilities like integrated steel mills. Our industries' extensive experience in voluntarily working to reduce energy consumption indicates that conducting the energy assessment described in the Proposed Rule at an integrated mill would be exceedingly costly - exclusive of the significant time and effort that plant personnel would need to dedicate to the task. Given our industries' existing focus on securing voluntary energy reductions, that significant expenditure would be duplicative and wasteful in many cases.

But more fundamentally, this undertaking is a means to no particular end. Any potential emission reductions, energy reductions, or non-air quality health and environmental benefits are not estimable because the proposed energy assessment requirement is just a study. While the Proposed Rule speculates that facilities may elect to implement certain findings, it cannot quantify any emissions reductions that may occur with the requisite level of certainty. Thus, this requirement fails EPA's traditional cost-effectiveness evaluation, which focuses on the annual cost per ton of HAP emissions eliminated. *See, e.g., Arteva Specialties S.A.R.L. v. EPA*, 323 F.3d 1088, 1089-90 (D.C. Cir. 2003). EPA apparently has not performed this calculation and it is impossible for any impacted entity to do so. While the Proposed Rule offers a rough emissions reduction estimate, 75 FR at 32026, that estimate apparently stems from presumed voluntary measures, with no solid indication that any HAP reduction will actually occur. Since there are no demonstrable emissions reductions from the proposed energy assessment requirement, the significant costs associated with that process are not warranted. As such, this proposed beyond-the-floor control fails the threshold test imposed by §112(d)(2).

Even if viable, the proposed energy assessment requirement presents serious implementation difficulties. One threshold problem is that the proposed energy assessment must be performed by "qualified personnel." These inspectors may well have a conflict of interest - particularly where their firms would stand to benefit from implementing any suggested modifications. As a result, regulated entities would have a difficult time delineating between truly appropriate modifications and those suggested by the evaluator in hopes of gaining additional business.

In addition, the number of personnel qualified to perform energy assessments is unknown. The Proposed Rule would require assessors to complete the Department of Energy's Qualified Specialist Program or become a Certified Energy Manager by the Association of Energy Engineers. 75 FR at 32026. Given the huge number of facilities impacted by the Proposed Rule and related Area Source standards,[21] there may well be a shortage of qualified personnel. That raises serious concerns, including: (1) personnel with significant experience and true expertise will be unavailable, (2) compliance may become difficult or impossible in a timely manner, and (3) competition for the limited pool of highly qualified assessors will cause their rates to increase significantly.

There would also be substantial inefficiency associated with getting a third-party inspector sufficiently "up to speed" to make informed conclusions regarding our industries' highly complex steelmaking operations. In contrast, existing operations personnel already have extensive steelmaking expertise and unique knowledge of the

[21] For major sources, 1,608 facilities would be required to conduct energy audits. Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants - Major Source, from S. McClutchey, A. Singleton & G. Gibson, to J. Eddinger, at §3.4 (Apr. 2010), Docket ID No. OAR-2002-0058-0812. Up to 94,339 area source facilities may also be required to conduct energy audits. Methodology for Estimating Impacts from Industrial, Commercial, Institutional Boilers at Area Sources of Hazardous Air Pollutant Emissions, from G. Gibson, S. McClutchey & A. Singleton, to J. Eddinger, at §3.2 (Apr. 2010), Docket ID No. OAR-2006-0790-0032.

particular processes at each of our industries' facilities. As such, they are better situated to make informed, realistic determinations of where energy reductions may be achievable than outside assessors - and at far lower cost. Indeed, they have already been doing so effectively for years at most of our industries' major facilities.

Finally, we are concerned that the proposed requirement to conduct a facility-wide energy assessment will be duplicative and unnecessary. As recognized in the Proposed Rule, fuel and energy costs are major drivers at many facilities.[22] That is particularly true for steelmaking companies that require large amounts of fuel and energy to operate. Given those existing business incentives, AISI members have already invested heavily to assess cost-effective energy efficiency opportunities. Further, we have made (and continue to make) significant voluntary investments implementing key efficiency projects - including under the EnergyStar program. Requiring facilities that have already completed these efforts to repeat that effort offers little practical benefit.

**<u>If EPA Adopts Numeric Emissions Limitations, the Final Rule Must Include a Separate Standard for Periods of Startup and Shutdown</u>**

The Proposed Rule does not include a separate standard for startup and shutdown. This is a fundamental problem that, if not corrected, will cause the final standards to be unachievable by even well designed and operated boilers. As a result, EPA must include a separate standard for startup and shutdown in the final rule.

EPA explains in the preamble that, "Based upon continuous emission monitoring data, obtained as part of the information collection effort for the major source boiler and process heater rulemaking, which included periods of startup and shutdown, over long averaging periods, startups and shutdowns will not affect the achievability of the standards." 75 FR at 31901. There are two fundamental problems with this justification for not including startup and shutdown standards in the rule.

First, EPA's emissions database provides continuous emissions monitoring system (CEMS) data from several of the better performing sources. Contrary to EPA's assertion in the preamble, these data show that daily average emissions should be expected to vary considerably on a day-to-day basis and that the variability spans the proposed levels of the standards. While it is difficult to discern the reasons for this variability based on the information provided in the database, there is little doubt that startups and shutdowns significantly contribute to the variable emissions performance

[22] Sector-Based Pollution Prevention: Toxic Reductions through Energy Efficiency and Conservation Among Industrial Boilers, The Delta Institute, at §3.2, Docket ID No. OAR-2002-0058-0842 (July 2002) (concluding that Fuel is traditionally the "most costly item associated with boiler operation").

of these units. Thus, the data indicate that EPA needs to include express accommodation for startups and shutdowns.

Second, basic scientific and engineering principles support the need for a separate standard for startup and shutdown. Particularly for CO emissions, combustion conditions will not be optimum during startup periods due to the generally low firing rate and the fact that the firing rate will be ramped up over the startup period. Thus, a significant period of non-optimum firing conditions will result in CO emissions performance - even on a daily average basis - that will be markedly different than performance during normal operations. EPA's failure to acknowledge these basic technical and engineering principles renders the proposed standards arbitrary.

For these reasons, we believe that a separate standard for startup and shutdown is needed and is amply justified. We suggest that a work practice standard is most appropriate due to the lack of relevant data and the fact that an emission testing during startup is not technically and economically practicable. If EPA decides that a numeric standard is needed, the Agency should rely on the available long term data from the better performing boilers to establish a standard with a reasonably long averaging time (such as a 30-day rolling average), rather than the proposed 24-hour averaging time.

**EPA Should Modify Table 5 to Include EPA Method 5B as an Expressly Approved Option for Determining Compliance with Proposed PM Emission Limits**

AISI supports EPA's proposal to use filterable PM as a surrogate for non-mercury metals. These metals, if present, will be contained within the solid PM entrained in the flue gas. Thus, the PM test method should focus on quantifying the solid PM that may contain HAP metals to the exclusion of volatile material, including sulfuric acid, that does not contain HAP metals but may condense on the Method 5 filter. Method 5B is designed to eliminate potential distortions to the quantification of solid PM caused by the presence of volatile sulfuric acid in the flue gas.

Table 5 to Subpart DDDDD of Part 63 - Performance Testing Requirements of the proposed rule should expressly include Method 5B in 40 CFR Part 60, Appendix A, which determines filterable non-sulfuric acid PM. Sulfuric acid is a volatile compound at flue gas temperatures that can partially condense and/or adsorb on the filter and collected solid PM. The dew point of sulfuric acid can extend above and below the filter temperature specified in Method 5 depending on sulfuric acid and water vapor concentration. In the presence of high concentrations of sulfuric acid, Method 5B is recommended to avoid distortions of the filterable particulate matter results caused by condensing sulfuric acid. To minimize this distortion, Method 5B modifies two parts of the standard Method 5 procedure: (1) the probe and filter are maintained at a higher temperature, 160±14°C (320±25°F), during sample collection; and (2) the probe rinse and filter are dried in an oven for 6 hours at 160±5°C (320±10°F), then cooled in a desiccator at room temperature for 2 hours, prior to gravimetric analysis.

EPA has implicitly recognized the benefits of a higher temperature probe and filter in allowing either Method 5 or Method 17 for determining compliance. In Method 5, the sample nozzle, probe and an *ex-situ* filter placed in a controlled temperature oven are maintained at 120±14°C (248±25°F). In Method 17, the filter and close-coupled sample nozzle are located *in-situ* within the stack and hence samples are filtered at stack gas temperature. Gas-fired industrial boilers at iron and steel manufacturers routinely operate with flue gas temperatures of approximately 200-260°C (approximately 400-500°F). Hence, the filtration temperature using Method 17 would be in that same range. In this application, the filter temperature for Method 5B is lower than the Method 17 temperature, but greater than the standard Method 5 temperature. Because the filter temperature for Method 5B may fall within the range allowed by the two methods proposed by EPA in Table 5, Method 5B is implicitly permitted in the proposed rule. To avoid ambiguity when interpreting the rule after finalization, we recommend that EPA expressly approve the use of Method 5B in the final rule.

Method 17 alone is insufficient to address the presence of sulfuric acid. First, Method 5B is often required as a test method for determining compliance with other regulatory particulate matter standards at facilities. Expressly including Method 5B in Table 5 of the rule would reduce the cost burden imposed on facilities by allowing a single test method to demonstrate compliance with the proposed MACT standard and other regulatory emission limits. Also, due to Method 17's in-stack apparatus, it is not an appropriate method for smaller stacks. *See* 40 CFR Part 60, Appendix A, Method 17, Section 1.2. EPA also states that Method 17 is not applicable for stacks that contain liquid droplets or that are saturated with water vapor. *Id.* Therefore, Method 5B is an appropriate and necessary addition to the approved methods in Table 5 of the proposed rule for quantifying filterable PM as a surrogate for non-mercury HAP metals.

**CO Monitoring Should be Limited to Those Subcategories Subject to CO Limits**

The Proposed Rule requires boilers or process heaters with a heat input capacity less than 100 MMBTU per hour to conduct a stack test for CO, but no CO standard is established in proposed 63.7500(a). Similarly, proposed §63.7510(c) requires a CO CEMS for boilers and process heaters with a heat input capacity equal to or greater than 100 MMBTU per hour, but no CO standard is established in proposed §63.7500. It makes no sense for testing to be conducted for a parameter for which no limit or surrogate is in place. AISI recommends that §63.7510(c) be amended to specify which subcategories are covered or limited to those units that are subject to the CO standard, by adding, for example: "If your boiler or process heater is subject to a CO limit and has a heat input capacity ...."

Similarly, Tables 1 through 3 do not establish a CO limit for gas subcategory 1 units. It is therefore not appropriate to require a CEMS for these units. The requirements for operation in accordance with good air pollution control practice (§63.7505(b)) and periodic burner tune-ups (§63.7540) is more than sufficient. The periodic tune-up gives an excellent assurance of compliance and burners in boilers and process heaters should vary very little over time. The requirement for good air pollution control practice minimizes this variation. There is an adequate assurance of compliance without the need for a CEMS.

__Emissions Averaging is Appropriate but Should Not be Penalized__

AISI supports EPA's use of emissions averaging as a flexible compliance alternative for facilities with multiple units. The Proposed Rule was correct to recognize emissions averaging as an "equivalent, more flexible, and less costly alternative to controlling certain emission points to MACT levels." *Id.* at 32034. That cost savings and additional flexibility comes at no environmental or health risk since overall emissions will fully comply with the promulgated MACT standards. However, AISI does not support the proposal to apply a "discount factor of ten percent" when emissions averaging is used to "further ensure that averaging will be at least as stringent as the MACT floor limits in the absence of averaging." 75 FR at 32035. This penalty erodes the very compliance flexibility that emissions averaging is designed to create without explaining why any penalty is necessary to uphold the stringency of the MACT floor.

The emissions averaging provisions in the 2004 Boiler MACT Rule were substantially similar to those in the current Proposed Rule. Both allowed sources to demonstrate compliance with certain emissions limits by averaging the emissions from one or more existing sources at the same facility that are in the same subcategory. *Compare* 75 FR at 32053, *with* 69 FR at 55257. Both required sources utilizing emissions averaging to take the following steps to ensure that implementation for these units would be no less stringent than unit-by-unit implementation: (1) demonstrate that the emission rate achieved during the compliance test does not exceed the emission rate that was being achieved at a set time after publication of the final rule, (2) demonstrate that the control equipment used during the compliance test is no less effective than it was at the same set time, and (3) develop and submit an emissions averaging implementation plan for approval. *Compare* 75 FR at 32053, *with* 69 FR at 55258-59.

EPA defended its inclusion of the emissions averaging compliance alternative in the 2004 Boiler MACT Rule as follows:

> EPA has concluded that it is permissible to establish within a NESHAP a unified compliance regimen that permits averaging across affected units subject to the standard under certain conditions. Averaging across

> affected units is permitted only if it can be demonstrated that the total quantity of any particular HAP that may be emitted by that portion of a contiguous major source that is subject to the NESHAP will not be greater under the averaging mechanism than it would be if each individual affected unit complied separately with the applicable standard. Under this rigorous test, the practical outcome of averaging is equivalent in every respect to compliance by the discrete units, and the statutory policy embodied in the MACT floor provisions is, therefore, fully effectuated.[23]

The 2004 Boiler MACT Rule did not contain any penalty provisions for emissions averaging, concluding that the safeguards enumerated above were sufficient. EPA has offered no explanation for why these steps are insufficient in 2010, or why a penalty of 10% is necessary to uphold the MACT floor for all sources. Nor did the intervening D.C. Circuit court decision offer any input on this topic. EPA is required to provide a "reasoned explanation ... for disregarding facts and circumstances that underlay ... prior policy." *FCC v. Fox Television Stations, Inc.*, 129 S. Ct. at 1810. EPA's decision to include a penalty provision in the Proposed Rule, given its prior defense of emissions averaging absent such a provision, is arbitrary and capricious.

**The Definition of Hot Water Heater Needs to be Revised**

In section IV.A of the preamble to the Proposed Rule, EPA states that the proposal would not regulate hot water heaters as defined in §63.7575. EPA recognizes that all hot water heaters meet the proposed definition of a boiler because they are enclosed devices that combust fuel for the purpose of heating water, but it is further stated that the when the hot water output from a hot water heater is intended for personal use rather than for use in an industrial, commercial, or institutional process, the hot water heater is more appropriately identified as a residential-type boiler and not an industrial, commercial, or institutional boiler.

EPA seeks to establish a definition for hot water heaters that would distinguish residential-type units or those used for non-process purposes from process-related units. However, the proposed definition bases the exemption solely on the size and output of the unit by limiting the capacity of an exempted hot water heater to 120 gallons, the pressure to 160 psig, and the temperature to 120 °F.

In order to maintain consistency with the rationale used to exempt hot water heaters, a hot water heater should be distinguished from a boiler by the intended use of

[23] Memorandum from Jim Eddinger, ESD Combustion Group, to Robert Wayland, ESD Combustion Group, re: Response to Public Comments on Proposed Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP (Feb. 25, 2004) (EPA-HQ-OAR-2002-0058-0611).

its output, not its physical parameters. Accordingly, AISI recommends the following revision to the definition in §63.7575:

> *Hot water heater* means a device in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for personal use and not for use in an industrial, commercial, or institutional process.

## CONCLUSION

As these comments show, EPA has both the need and the opportunity to make significant changes to the proposed Boiler MACT. These changes are needed to correct fundamental technical and data issues that compromise the validity of the proposed standards. They also are needed to address several basic legal infirmities that call into question the legal viability of key aspects of the rule. Lastly, EPA can and should take advantage of the several significant opportunities described above that would substantially reduce the burden on affected sources while still providing ample protection to health and the environment.

In closing, it is apparent that, even with the changes suggested above, owners and operators, including iron and steel manufacturing facilities, will be required to retrofit countless industrial boilers and process heaters in order to meet the final rule. The proposal would set a three-year compliance deadline for existing affected sources. However, this is an exceedingly short time given the extensive nature of the needed retrofits and the limited technical resources available to accomplish the retrofits (especially in light of the fact that industrial boiler owners will be competing for equipment and technical resources with other key industry sectors such as the utility sector, which will have a similar compliance deadline for the utility MACT and also will be required to install substantial air pollution controls to meet EPA's proposed Clean Air Transport Rule).

To solve this problem, EPA must adopt a significantly longer compliance deadline. Nominally, EPA should adopt by rule an across-the-board one-year extension pursuant to §112(i)(3)(B). However, even a four-year compliance period will be inadequate for many affected sources. Therefore, EPA should provide additional time by: (1) granting in the final rule a Presidential extension under §112(i)(4), given that it is in the "national security interests of the United States" to prevent widespread noncompliance in the industrial base; (2) declaring that the statutory three-year compliance period is impossible to meet or otherwise produces "absurd results," which as demonstrated in EPA's recent PSD Tailoring Rule are doctrines that allow EPA to depart from clear statutory directives in appropriate circumstances; and/or (3) establishing phased or sequenced requirements such that certain element of the rule become effective no later than three years after promulgation (thus satisfying §112(i)(3)(A)), while others are phased in at later times.

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We appreciate the opportunity to offer our views on this important proposed rule. If EPA staff has any questions on our comments, please feel free to contact Bruce Steiner at 202-452-7198 or bsteiner@steel.org.

Sincerely,

/s/ Kevin M. Dempsey

Kevin M. Dempsey
Vice President, Public Policy and General Counsel

Attachments

Table 1. Typical process gas analysis.

| Fuel Gas Component | Formula | Units | COG | BFG |
|---|---|---|---|---|
| Methane | CH4 | %v | 26.6% | 0.011% |
| Ethene | C2H4 | %v | 2.3% | |
| Ethane | C2H6 | %v | 0.8% | |
| Propene | C3H6 | %v | 0.2% | |
| Propane | C3H8 | %v | 0.0% | |
| Butenes | C4H8 | %v | 0.0% | |
| Butanes | C4H10 | %v | 0.0% | |
| C5+ | C5+ | %v | 1.0% | 0.01% |
| Hydrogen | H2 | %v | 60.1% | 5.98% |
| Carbon monoxide | CO | %v | 4.9% | 23.45% |
| Carbon dioxide | CO2 | %v | 1.2% | 23.40% |
| Nitrogen | N2 | %v | 2.7% | 46.53% |
| Oxygen | O2 | %v | 0.2% | 0.61% |
| Total | | %v | 100.00% | 100.00% |
| Gross Heating Value | HHV | BTU/scf | 575.2 | 93.5 |

Table 2. Fuel heat input to each unit during tests (**preliminary data, subject to QC review**).

| Test Date | Test Run | Boiler No. | Total Heat Input MMBTU/hr | Percent of Rated Maximum Heat Input Capacity | Blast Furnace Gas | | Coke Oven Gas | | Natural Gas | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Heat Input MMBTU/hr | Percent of Total Heat Input | Heat Input MMBTU/hr | Percent of Total Heat Input | Heat Input MMBTU/hr | Percent of Total Heat Input |
| Jul-2010 | Average | A | 540 | 83 | 198 | 37 | 275 | 51 | 67 | 12 |
| Jul-2010 | Average | B | 541 | 83 | 184 | 34 | 295 | 54 | 63 | 12 |
| Jul-2010 | Average | C | 525 | 81 | 182 | 35 | 277 | 53 | 65 | 12 |
| Jul-2010 | Average | D | 559 | 86 | 288 | 52 | 236 | 42 | 35 | 6 |
| Min | All | All | 476 | 73 | 163 | 30 | 191 | 34 | 34 | 6 |
| Max | All | All | 568 | 87 | 329 | 59 | 324 | 60 | 73 | 14 |
| Mean | All | All | 541 | 83 | 213 | 39 | 271 | 50 | 57 | 11 |
| Median | All | All | 542 | 83 | 195 | 36 | 276 | 52 | 64 | 12 |

**<u>Table 3</u>: Summary of Test Results for four coke oven gas-fired boilers**

| Pollutant (Method) | Units | Gas 2 Proposed | Boiler A mean | | Boiler B mean | | Boiler C mean | | Boiler D mean | | All Boilers mean | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PM (26A/5B) | lb/MMBTU | 0.05 | DLL | 0.001 | DLL | 0.004 | DLL | 0.001 | ADL | 0.030 | DLL | 0.009 |
| PM (29/5B) | lb/MMBTU | 0.05 | ADL | 0.004 | ADL | 0.013 | DLL | 0.001 | ADL | 0.004 | DLL | 0.006 |
| PM (101A/5B) | lb/MMBTU | 0.05 | DLL | 0.001 | ADL | 0.012 | DLL | 0.002 | ADL | 0.005 | DLL | 0.005 |
| PM (All) | lb/MMBTU | 0.05 | DLL | 0.002 | DLL | 0.010 | DLL | 0.001 | ADL | 0.013 | DLL | 0.007 |
| HCl (26A) | lb/MMBTU | 3.0E-06 | ADL | 8.5E-04 | ADL | 3.8E-03 | ADL | 1.7E-04 | ADL | 1.9E-03 | ADL | 1.7E-03 |
| Hg (EPA 29) | lb/MMBTU | 2.0E-07 | DLL | 5.1E-06 | DLL | 8.1E-06 | DLL | 4.9E-06 | DLL | 5.2E-06 | DLL | 5.8E-06 |
| Hg (EPA 101A) | lb/MMBTU | 2.0E-07 | DLL | 5.7E-06 | DLL | 7.9E-06 | ADL | 6.2E-06 | ADL | 5.2E-06 | DLL | 6.3E-06 |
| Hg (All) | lb/MMBTU | 2.0E-07 | DLL | 5.5E-06 | DLL | 5.2E-06 | DLL | 5.4E-06 | DLL | 8.0E-06 | DLL | 6.0E-06 |
| CO | ppm @ 3% O2 | 1 | DLL | 9.2 | DLL | 4.8 | DLL | 0.04 | ADL | 93 | DLL | 27 |
| D/F (EPA 23) | ng/dscm @ 7% O2 | 9.0E-03 | DLL | 2.2E-03 | DLL | 1.1E-03 | DLL | 1.3E-03 | DLL | 1.5E-03 | DLL | 1.6E-03 |

ADL=above detection limit; BDL=below detection limit; DLL=detection level limited. For CO measurements, results less than 2% of the analyzer range are considered BDL.

**<u>Table 4</u>: Hypothetical emission control efficiencies and controlled HCl, mercury and CO emission levels for coke-oven gas-fired units, illustrating the technical infeasibility of achieving proposed Gas 2 emission limits for coke oven gas-fired units.**

| Pollutant (Method) | Units | Gas 2 Proposed | Boiler 8 mean | | Boiler 9 mean | | Boiler 11 mean | | Boiler 12 mean | | All Boilers Mean | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HCl uncontrolled | lb/MMBTU | | ADL | 8.5E-04 | ADL | 3.8E-03 | ADL | 1.7E-04 | ADL | 1.9E-03 | ADL | 1.7E-03 |
| Control efficiency | % | | | 99% | | 99% | | 99% | | 99% | | 99% |
| HCl controlled | lb/MMBTU | 3.0E-06 | | 8.5E-06 | | 3.8E-05 | | 1.7E-06 | | 1.9E-05 | | 1.7E-05 |
| Hg uncontrolled | lb/MMBTU | | DLL | 5.5E-06 | DLL | 5.2E-06 | DLL | 5.4E-06 | DLL | 8.0E-06 | DLL | 6.0E-06 |
| Control efficiency | % | | | 80% | | 80% | | 80% | | 80% | | 80% |
| Hg controlled | lb/MMBTU | 2.0E-07 | DLL | 1.1E-06 | | 1.0E-06 | | 1.1E-06 | | 1.6E-06 | | 1.2E-06 |
| CO uncontrolled | ppm @ 3% O2 | | DLL | 9.2 | DLL | 4.8 | DLL | 0.4 | ADL | 93 | DLL | 27 |
| Control efficiency | % | | | 90 | | 90% | | n/a | | 90% | | 90% |
| CO controlled | ppm @ 3% O2 | 1 | BDL | 0.9 | BDL | 0.5 | | | DLL | 9.3 | DLL | 2.7 |

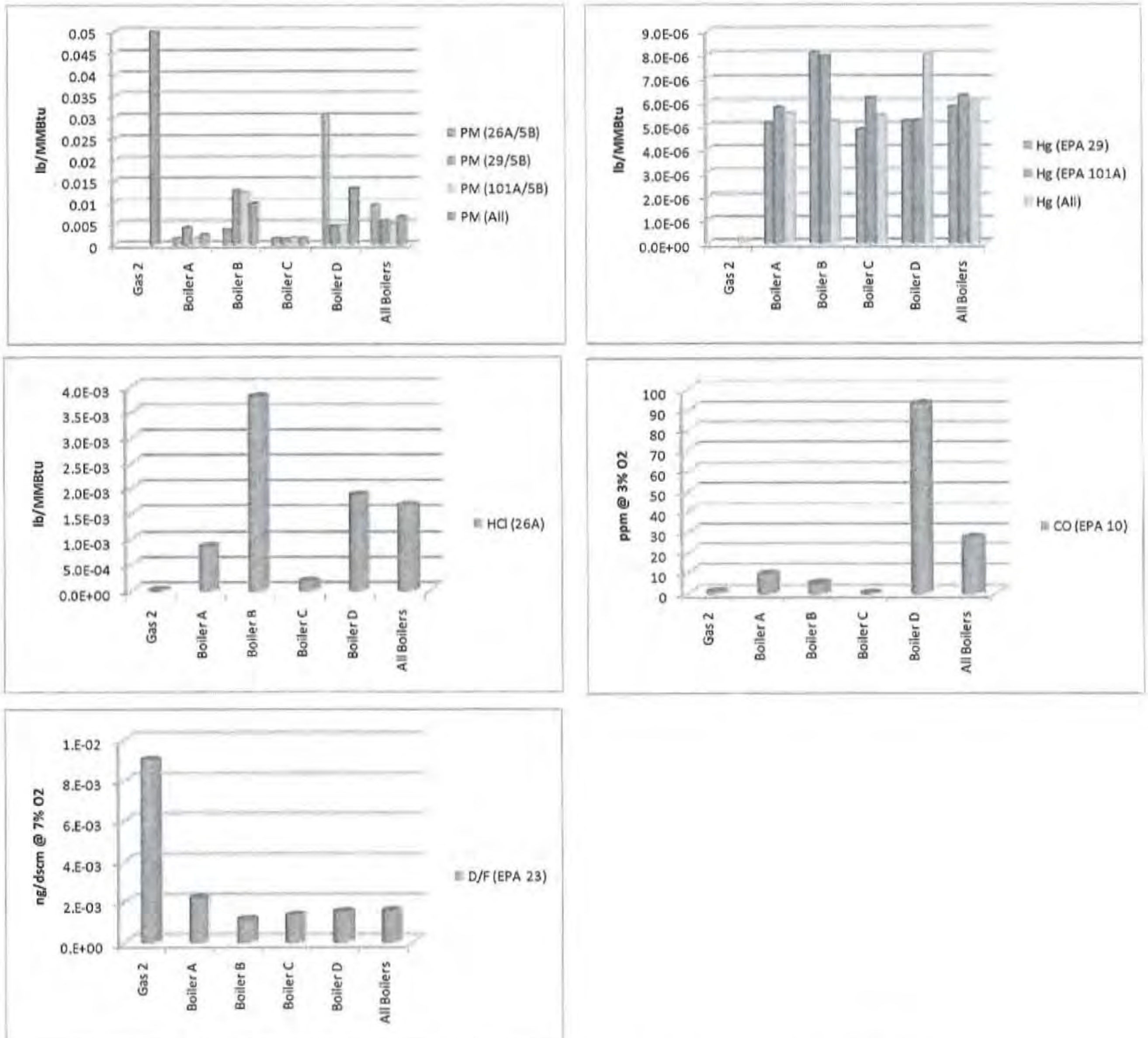


Figure 1. Summary of average test results for four coke oven gas-fired boilers compared to Gas 2 emission limits.