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

May 20, 2011

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

RE: Petition for Reconsideration of the National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers, 76 Fed. Reg. 15,554 (Mar. 21, 2011) (Docket No. EPA-HQ-OAR-2006-0790)

Dear Administrator Jackson:

INTRODUCTION

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

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

On June 4, 2010, EPA proposed the National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers (75 Fed. Reg. 31,898). On August 23, 2010, the comment period closed. On March 21, 2011, EPA published the final Area Source Rule. 76 Fed. Reg. 15,554.

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

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

I. O2 MONITORING REQUIREMENTS.

A. Petitioners Were Not Given the Opportunity to Comment on the New O2 Monitoring Requirement Contained in the Final Area Source Rule.

The final Area Source Rule creates new O2 monitoring requirements that were not included in the proposed rule, depriving sources of notice and an opportunity to comment. EPA should therefore reconsider this issue

The final Area Source Rule imposes a CO emission limit on coal fired subcategories with compliance proven by a triennial Method 10 CO emission test, in combination with an O2 operating limit proven with an O2 CEMS. 76 Fed. Reg. 15,594. While CIBO agrees that CO CEMS should not be required for units under Subpart DDDDD or Subpart JJJJJJ, the O2 monitoring requirements as finalized are not appropriate or workable in some cases and additional flexibility is required.

In the proposed Area Source rule, EPA established CO emissions limits for several subcategories of sources, with compliance demonstrated as a 3-run average for units less than 100MMBtu/hr and on a daily average basis using a CO CEMS for units 100MMBtu/hr or greater. Although CO CEMS monitoring was required at all times, CO data was only used when operating at 50 percent of rated capacity or greater.

In the final rule Area Source Rule, EPA eliminated some of the CO emission limits, removed the CO CEMS requirement. Instead, EPA is requiring triennial Method 10 CO performance testing to demonstrate compliance by those units with CO emission limits and the use of an O2 CEMS to demonstrate compliance on a 12-hour block average basis with the minimum O2 operating limit established during performance testing. 76 Fed. Reg. 15,595-596.

EPA is requiring that the oxygen level shall be monitored at the outlet of the boilers. Each monitor must be installed, operated, and maintained according to the applicable procedures under Performance Specification 3 at 40 CFR part 60, appendix B, and according to the site-specific monitoring plan developed according to paragraph (c) of this section. 76 Fed. Reg. 15,595. The rule further requires monitoring of oxygen content in the combustion exhaust and the maintenance of the 12 hour average at or above the operating limit established during most recent performance test. 76 Fed. Reg. 15,605.

While CIBO agrees that CO CEMS are not an appropriate mandatory monitoring requirement for a CO limit based on stack test data obtained at full load conditions, monitoring O2 levels in the stack or ductwork leading to the stack to ensure continuous compliance is not appropriate for all units. Many existing boilers already utilize flue gas oxygen analyzers for indication, alarm, and O2 trim control, where the fuel/air ratio is automatically controlled for optimum combustion conditions. The sensing location for existing O2 monitors is typically in the optimum location to sense flue gas composition as reliably as possible, because sensing of oxygen in these cases maintains proper excess air levels and helps prevent unsafe operating conditions. For many types of combustion units, that location is near the boiler or process heater furnace outlet in a position upstream of any potential air inleakage points to avoid erroneous excess air indications. This location is also upstream of air preheaters where utilized, thus avoiding the erroneous (high O2) indications due to inherent leakage across regenerative air preheater seals or potential tube leakage in recuperative air preheaters.

For those units equipped with existing O2 sensors and O2 trim control systems, flue gas composition at those locations would already be used for combustion tuning and control characterization. Therefore, if O2 monitoring was desired for continuous compliance under the Area Source Rule, sensing O2 at that current location would be logical and proper from a technical perspective. However, O2 analyzers utilized for these existing purposes are not compliant CEMS meeting PS-3 requirements relative to positioning or other QA/QC requirements. They are, however, calibrated and maintained to provide reliable and safe service for combustion unit operation.

Conversely, if O2 was sensed prior to the stack or in the stack, that would be downstream of potential air inleakage points and air preheater leakage points, thus leading to variations in readings that can impact operation and long term compliance. It must be recognized that where CO or NOx CEMS are utilized in the stack with O2 or CO2 correction, that O2 or CO2 reading purposely corrects for variations in excess air from the furnace as well as any air inleakage or internal air heater leakage, so the impact is not of consequence from a combustion safety or direct compliance perspective. However, if it is required to actually monitor and maintain O2 level, then the most appropriate location for sensing that O2 level is upstream of any potential leakage points. By definition, those locations will not meet PS-3 requirements due to their close coupled nature and use of single or multiple point sensors that are most appropriate for the application.

The most cost effective approach for utilization of O2 CEMS would be to allow the option of continued use of existing O2 analyzers and use of new O2 analyzers of appropriate design for the application to be located in optimum positions for the particular unit involved. Requiring periodic sensor calibration would be a way to ensure accurate O2 monitoring. If new O2 sensors are required in all cases in the breeching or stack to meet PS-3 requirements, it would be an unjustified additional capital and ongoing O&M expense that will not provide any constructive compliance information. There are some units where locating O2 sensors in the breeching or stack is appropriate, so options should be provided to allow optimum monitoring.

As previously noted, the O2 monitoring requirement is new in the final Area Source Rule and petitioners were not given an opportunity to comment on its use. Considering this, EPA should reconsider this new requirement.

B. EPA's CO Emission Limits Were Established Incorrectly.

Some existing area source boilers are already required to use CO CEMS. In those cases, even with the final rule as written, instantaneous CO spikes could be considered credible evidence leading to deviations if those readings under any operating conditions exceed the CO limits that were established using reference method test data at maximum unit operating load. It is well known that CO emissions vary widely over normal load conditions.

However, in addition to units required to use CO CEMS, there may also be units that would prefer to install CO CEMS, so that an alternative CO limit based on use of CEMS is needed. It would be much more appropriate and cost effective for regulated facilities and regulatory authorities if EPA would provide alternative CO limits and their basis for facilities to utilize CO CEMS instead of O2 CEMS, rather than requiring individual facilities to petition for alternative monitoring practices.

In order to allow for use of CO CEMS with O2 correction, EPA needs to establish CO emission limits on an appropriate basis using emission data on the same basis, i.e CEMS data. Since the final rule provides work practices for startup/shutdown periods, an appropriate basis for a CO limit using a CO CEMS would be a 30-day rolling average based on actual CO readings over the appropriate operating range.

CIBO notes that there are other issues related to the O2 provisions of the final Area Source Rule. Specifically, O2 compliance basis for O2 CEMS is given as 30 day rolling average. This appears to be an error since it is a12-hour block average that is required in the rule. *See* Table 7, 76 Fed. Reg. 15,596. However, the word “block” is missing in Table 7 item 7 for O2 and item 6c for ESP secondary amperage and voltage. Id. These two should be clarified to be block averages if that is EPA’s intent.

II. ENERGY ASSESSMENT

A. EPA Unreasonably Failed to Treat Certain CBI Similarly Under the Major and Area Source Rules.

In several documents referenced below, EPA stated its intent to recognize in the final Area Source Rule the sensitivity of confidential business information (CBI) contained in energy assessments. Despite this fact, it appears that EPA did not fully incorporate its intentions with regard to the treatment of CBI in the final Area Source Rule. Considering this, EPA should reconsider the text § 63.11241(c) and clarify that energy assessment reports are not required to be submitted to the Agency.

In the proposed Area Source Rule, proposed § 63.11215(b) required that:

> [i]f you own or operate an existing affected boiler with a heat input capacity of 10 million Btu per hour or greater, you must submit the energy assessment report, along with a signed certification that the assessment is an accurate depiction of your facility.

In the final Area Source Rule, § 63.11214(c) requires that:

> [i]f you own or operate an existing affected boiler with a heat input capacity of 10 million Btu per hour or greater, you must submit a signed certification in the Notification of Compliance Status report that an energy assessment of the boiler and its energy use systems was completed and submit, upon request, the energy assessment report. 76 Fed. Reg. 15,594.

It appears that in the final Area Source Rule, EPA requires submission of the energy assessment report only upon request. This approach is contrary to the approach taken in the final Boiler Rule, where § 63.7530(e) provides:

> [y]ou must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility. 76 Fed. Reg. 15,675.

Considering the express text of the final regulations, submission of energy assessment reports is not required under the final Boiler rule. CBI is equally an issue for companies operating area source boilers as it is for major source boilers and process heaters. As such, a similar approach in both rules is justified. EPA has provided no justification for requiring submission of the energy assessment reports for area sources while not requiring their submission for major sources. From a review of its response to comments it appears it was EPA's intention to treat energy assessment reports for area sources similarly to their treatment for major sources. Specifically, in the RTC, Vol.2, p.461, EPA states:

> In the final rule, the energy assessment is not required to be submitted to EPA or the permitting agency. The final rule requires that the permitting agency be notified that the energy assessment has been conducted according to the requirement in the final rule. The facility is required to keep records that the work practices and management practices were complied with.

It appears that EPA did not fully incorporate its intentions with regard to the treatment of CBI in the final Area Source Rule. Considering this, CIBO recommends that EPA reconsider revising the text of § 63.11241(c) to read as follows:

> "If you own or operate an existing affected boiler with a heat input capacity of 10 million Btu per hour or greater, you must submit a signed certification in the Notification of Compliance Status report that an energy assessment of the boiler and its energy use systems was completed **according to Table 2 of this subpart and is an accurate depiction of your facility** ~~and submit, upon request, the energy assessment report~~.

B. EPA Should Clarify the Scope of the Energy Assessment.

EPA appears to have intended that the scope of the energy assessments be limited to those components associated with the energy output from boilers that are regulated by the rule. Despite many indications that this was EPA's intent, the actual text of the final Area Source Rule appears to include a broad scope of what is included in the energy assessment. Considering this, EPA should reconsider these provisions and clarify its intent with regard to the scope of the energy assessment.

In the proposed Area Source Rule, EPA defined "Energy Assessment" as follows:

> *Energy assessment* means an in-depth assessment of a facility to identify immediate and long-term opportunities to save energy, focusing on the steam and process heating systems which involves a thorough examination of potential savings from energy efficiency improvements, waste minimization and pollution prevention, and productivity. 75 Fed. Reg. 31,931.

As indicated in the energy assessment definition, the focus was on the steam and process heating systems (though process heaters were not within the scope of the rule).

In the final Area Source Rule preamble, EPA includes a discussion of the energy assessment:

> …we have carefully limited the requirement to perform an energy assessment to **specific portions of the source that directly affect emissions from the affected boiler**, as indicated by the revised definition of an energy assessment in section 63.11237 of subpart JJJJJJ. **The emissions that are being controlled come from the affected source.** For coal-fired units, **the process changes resulting from a change in an energy using system will reduce the volume of emissions at the**

> **affected source.** For biomass-fired and oil fired area sources, **better management practices at energy using systems will reduce the emissions of HAP from the affected source by reducing fuel consumption and the HAP released through combustion of fuel. In either case, the requirement controls the emissions of the affected source.** 76 Fed. Reg. 15,568 (emphasis added).

EPA discusses further that the purpose of an energy assessment is to "to reduce the facility energy demand which would result in reduced fuel use." 76 Fed. Reg. 15,573. EPA stated that it is not the Agency's intent to "to require an energy assessment for the entire facility; the energy assessment is only applied to existing boilers and their energy use systems located at area sources…." Id. Furthermore, EPA provides in the final Area Source Rule that it added the "energy use systems" definition for the purpose of clarifying that:

> the components for each boiler system and energy use system which must be considered during the energy assessment, including elements such as combustion management, thermal energy recovery, energy resource selection, and the steam end-use management of each affected boiler. These revisions clarify that an energy assessment is only required for those portions of the facility using the energy generated from the affected boiler system. Id.

Considering this rather lengthy discussion, it is obvious that it was EPA's intention to limit the scope of the energy assessments to that which was associated with the energy output from boilers regulated by the rule.

Nonetheless, EPA defines "Energy use system" to include "energy use which in many cases is only associated with electricity use, i.e., compressed air systems, machine drive (motors, pumps, fans), process cooling, facility HVAC, building envelop(e), and lighting). 76 Fed. Reg. 15,600. In other provisions of the Final Area Source Rule, EPA provides that where this electricity is purchased from others (such as an electric utility), it has no impact on the combustion unit fuel use or associated emissions regulated by this rule, and thus is outside the intended scope of the assessment (see above). Energy assessment under Subcategory 4, item (7) includes cost of specific improvements, benefits, and time frame for recouping investments. 76 Fed. Reg. 15,602. This is an expansion from the proposed rule that will require significant time and effort for some level of design and estimating to determine vs. time limits earlier in the rule. Considering these issues, clarification needs to be made to the rule to exclude those energy uses that are not associated with combustion sources on the site.

Furthermore, it is noted that Table 2, Subcategory 4, item (3) is worded differently than in the DDDD- "Inventory of major systems consuming energy from affected boiler(s)," so that the inventory is limited to boiler energy output. But item (2) of that section requires an evaluation of specifications of **energy using systems**. 76 Fed. Reg. 15,602. Therefore, there are inconsistencies within various provisions of JJJJ. Because the *Energy use system* definition was changed in the final rule relative to the proposed rule, EPA should reconsider these issues.

EPA needs to clarify that the scope of the energy assessments is to be limited to those facilities and equipment associated with the energy output from the boilers regulated under Subpart JJJJJJ. In those cases where cogeneration is incorporated into the facility utilizing steam output from the regulated boilers and the cogenerated electrical output is utilized on site, then incorporation of those electricity using facilities and equipment is legitimately included within the scope of the energy assessment.

C. EPA Should Clarify that the "Stated Maximum Times" Are Mere Estimates That the Agency Cannot Rely on for Enforcement Purposes.

EPA includes in the final Area Source Rule a definition for the "stated maximum time" to conduct an energy assessment. None of the maximum times were included in the proposed rule. Considering this, CIBO members had no opportunity to comment and EPA should therefore reconsider these issues.

In the final Area Source Rule, EPA provides that the "stated maximum time" for conducting an energy assessment, i.e., one day maximum for <0.3TBtu/yr heat input and 3 days maximum for 0.3 to 1 TBtu/yr heat input. 76 Fed. Reg. 15,600. This phrasing could imply that a deviation and a potential violation could occur if the energy assessment effort exceeded those time limits. EPA should reconsider and clarify that these times are actually "expected" maximum times for conducting the assessments. EPA should recognize that actual times can exceed those figures depending on site specific conditions. This clear statement is critical so that deviations or enforcement is not applicable to the elapsed times expended on energy assessments.

D. EPA Lacks Authority to Mandate the Energy Assessment

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

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

A significant amount of testing will be required by sources to determine the compliance status with respect to the rule and to evaluate and select available control strategies. Capital projects to install necessary control equipment cannot proceed until the testing and evaluation is complete. Due to the high number of sources affected by the rule that have the same concerns, it is likely that availability of stack testing personnel and laboratory facilities to conduct tests will be limited, adding to the time required to complete this essential first step. As outlined below, annual compliance testing requiring multiple test runs for purposes of compliance will further reduce the availability of testing and laboratory resources. During the reconsideration process, EPA should revise the emission testing requirements so that frequency of testing is not more then every 5 years.

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

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

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

IV. EMISSIONS AVERAGING

A. EPA Should Include Emissions Averaging for Area Sources.

EPA included emissions averaging as a compliance option in the final Boiler Rule, and this should be a compliance option for area sources as well. EPA has previously noted that the Small Business Administration Panel "recommended that EPA carefully weigh the potential burden of compliance requirements and consider for small entities options such as, emission averaging within facility. . . " 75 Fed. Reg. 31,919. Although EPA asserts that it "proposed provisions consistent with each of the Panel's recommendations regarding area source facilities," EPA did not include in the final Area Source Rule an emission averaging compliance alternative for area sources. EPA has further acknowledged that "emissions averaging represents an equivalent, more flexible and less costly alternative to controlling certain emission points to MACT levels" and its application "would not lessen the stringency of the MACT floor limits and would provide flexibility in compliance, cost and energy savings to owners and operators." 75 Fed. Reg. 32,034.

During the reconsideration process, EPA should adopt this flexible compliance alternative for area sources.

B. EPA Should Not Include a 10% Discount Factor.

In the final Boiler Rule, EPA includes a restriction on emissions averaging that requires facilities using that option to meet a standard that is 10% stricter than the otherwise applicable limits. 76 Fed. Reg. 15,670. EPA should not include this 10% penalty for using emissions averaging because it is arbitrary, unnecessary for environmental protection and reduces the flexibility that averaging provides.

Given the accuracy of heat input weighted emission calculations, there is no uncertainty that the average emission rates will be any less stringent than when not using averaging. Because EPA has already determined that the standards in the rule achieve the maximum emission reduction achievable for health and environmental protection, to require an additional 10% reduction of emissions has no basis in the environmental underpinnings of the rule. Because emissions averaging is a compliance alternative, the 10% discount factor would constitute a beyond-the floor requirement. Although the 10% discount may be perceived as a fair trade-off for the flexibility of emissions averaging, it still lacks a legal basis and creates a disincentive for sources to use this compliance method. Where, as here, proposed emission limits are very tight, sources will not be able to ensure an additional 10% reduction in emissions below the limits and imposing this penalty effectively would deprive many sources of the availability of the emissions averaging compliance alternative.

V. ISSUES NEEDING CLARIFICATION

A. EPA Should Revise the Definition of "Natural Gas Curtailment."

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

NG curtailment is defined in the Area Source Rule:

> *Period of natural gas curtailment or supply interruption* means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption. 76 Fed. Reg 15,601.

This definition is apparently written to protect those firms whose supply is downstream of a Local Distribution Company. Users downstream of a LDC can indeed have their supply halted when the needs of users exceed the LDC's available supply. In such a scenario, residential users

(& hospitals, etc) would be given priority and an industrial firm would be shut off. This definition is a good and constructive thing for such users.

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

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

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

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

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

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

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

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

VI. TECHNICAL CORRECTIONS

A. EPA Should Clarify Subpart DDDDD, Table 7 - Demonstrating Continuous Compliance.

Subpart DDDDD, Table 7, Item 1.c. includes the word "block" in stating the following requirement: "Maintaining opacity to less than or equal to 10 percent (daily block average)." 76 Fed. Reg. 15,605. It appears that other similar requirements do not include the word "block" in the compliance requirement statement. Considering this, EPA should revise the following items in Table 7 as noted below for clarity and to reduce potential confusion:

3.c. "Maintaining the 12-hour **block** average pressure drop…"

4.c. "Maintaining the 12-hour **block** average sorbent or carbon injection rate…"

5.c. "Maintaining the 12-hour **block** average secondary amperage and voltage, or total power input…"

7.b. "Maintaining the 12-hour **block** average oxygen content…"

B. EPA Should Clarify the Requirements of Section 63. 11220.

It appears that there are conflicting requirements in § 63.11220. 76 Fed. Reg. 15,594. Specifically, paragraph (a) requires triennial performance tests; however, paragraphs (b) and (c) incorporate the wording from Subpart DDDDD relative to 3 consecutive years' results <=75% of emission the limit in order to go to triennial testing. Considering this, EPA should delete §§ 63.11220(b) and 63.11220(c) to eliminate incorrect and conflicting statements.

C. EPA Should Clarify that the Area Source Rule Does Not Apply To Process Heaters.

As indicated in § 63.11193, the final Area Source Rule is only applicable to boilers, not process heaters. 76 Fed. Reg. 15,591. Despite this fact, EPA references process heaters in paragraphs (2) and (3) of the definition of "*Energy assessment.*" 76 Fed. Reg. 15,600. EPA should revise both of those paragraphs to delete the term *"process heater."* This will help to avoid confusion and maintain consistency with rule applicability.

CONCLUSION

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

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

Sincerely yours,

/s/ Robert D. Bessette

Robert D. Bessette
President