Comments on the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and <u>Process Heaters: Non-Continental Liquids Subcategory</u>

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Dear Brian:

The final National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (76 Fed. Reg. 15608, March 21, 2011) established a subcategory for units designed to burn liquid fuel that is a non-continental unit (i.e., an industrial, commercial, or institutional boiler or process heater designed to burn liquid fuel located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.) That regulation is currently stayed pending reconsideration[1]. API/NPRA filed a reconsideration petition on May 20, 2011 detailing the broad list of issues that we believe require review.

API and NPRA members operate many boilers and process heaters in non-continental locations. Because there is no practical access to natural gas in non-continental locations, many of these units must fire liquid fuels or fire liquids when internally generated gases are unavailable. Thus, we are vitally interested in assuring that the applicable requirements for the Non-Continental Liquids Subcategory are reasonable, achievable, and cost effective. To further the reconsideration process, API and NPRA offer the following comments as a supplement to our May 20, 2011 petition and data to improve the basis for the emission limitations established for the Non-Continental Liquids Subcategory.

[1] 76 FR 15266 (March 21, 2011)

1. The regulation establishes a numerical emission limit for particulate (PM) of 0.0075 lb per MMBTU of heat input (30-day rolling average for residual oil fired units 250 MMBTU/hr or greater, 3-run average for other units) for existing units and 0.0013 lb per MMBTU of heat input (30-day rolling average for units 250 MMBTU/hr or greater, 3-run average for units less than 250 MMBtu/hr) for new units. These limits were established based on the data available for the Continental Liquids Subcategory because the Agency did not have any PM test data for non-continental units (Chevron data for a non-continental process heater were submitted after the close of the public comment period). Attached as Attachments 1, 2 and 3 are PM test reports for three Non-Continental Liquids Subcategory unit tests (a Chevron process heater and two tests on a Tesoro boiler) for your use in establishing limits specific to this subcategory. These test reports confirm there is considerable variability between units, which reflects the differences in the fuels non-continental units must feed (i.e., fuels produced in their own refining operations) and the different burner designs that result from having to have the capability to burn both liquid and gaseous fuels. In this case, the Tesoro boiler can burn either liquid or gaseous fuels, but not at the same time; while the Chevron process heater can fire both liquid and gaseous fuels in the same burners at the same time (though it was only burning fuel oil during this test). It is critical that the variability reflected in these test reports be appropriately addressed in developing the PM limitation for the Non-Continental Liquids Subcategory.

Applying the same approach to variability to these Non-Continental Liquid units as was done for the Continental Liquids subcategory, and as described in ERG's memo "Revised MACT Floor Analysis (2011) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source," results in a calculated upper prediction limit (UPL) of 0.31 lb per MMBTU of heat input at a 99% confidence level[2]. Basing the existing source PM standard on this calculated UPL is a reasonable approach for EPA to use in addressing the variability of PM emissions from these specific units.

In consideration of the best performing source for establishing the PM standard for new sources in the Non-Continental Liquid Subcategory, it is important to note that the fuel for the top ranked unit (Tesoro's SG-1102) is specific to the Tesoro refinery and cannot be reasonably purchased or obtained by other sources in the subcategory. Consistent with the HCl MACT floor for new boilers designed to burn liquid fuel, the Hg MACT floor for new boilers designed to burn solid fuel, and the CO MACT floor for new fluidized bed boilers designed to burn biomass, and as described in ERG's previously-cited memo (page 24), we request that EPA utilize the next lowest emissions as the basis for the floor calculations. Using the second lowest test average for the PM MACT floor for new Non-Continental Liquid units results 0.078 lb per MMBTU, based on the calculated 99% UPL[2].

[2] The calculation of these recommendations is shown in Attachment 4, which provides the new information and calculations in the same format used by EPA in the floor analysis supporting the stayed rule.

2. The regulation establishes a numerical emission limit for Mercury (Hg) of 7.8E–07 lb per MMBTU of heat input for both existing and new units.

The data for mercury for non-continental unit fuels that served as the basis for the numerical emission limit is very limited. We have located data on four additional samples from two other non-continental refineries and provide it as Attachments 5 and 6. Because non-continental refineries are using fuels that they produce there is considerable variation in mercury emissions over time and between non-continental refineries. Basing the Hg limit on a few samples from only one refinery (as was done for the stayed rule) without considering inter-refinery variability due to fuel and crude constraints, virtually assures significant compliance challenges for all other non-continental refineries. Furthermore, since these refineries are the only sources of supply for non-refinery boilers and process heaters at non-continental locations, establishing a limit that some refinery units in non-continental locations cannot meet means many non-refinery units will also be unable to meet them. We encourage EPA to consider carefully the potential impacts on island economies of setting unattainable Hg limits or of unnecessarily forcing expenditures for mercury and the associated PM controls on many non-continental boilers and process heaters.

There are significant issues associated with the measurement of mercury that need further consideration. The data for mercury for non-continental unit fuels that served as the basis for the numerical emission limit in the stayed rule were from a single refinery and were determined using a method not delineated as an approved method in Table 6 of the rule. The results from this different method indicated mercury levels far below the typical detection limit of the method prescribed in Table 6 (EPA SW-7471B), as shown in the additional samples attached to this letter. The use of unapproved methods and methods where sample times have been extended show the difficulty of measuring mercury in fuels at the low levels typically present. Having to resort to such approaches demonstrates that the application of measurement methodology for mercury to non-continental unit fuels is not practicable. We encourage EPA to consider a work practice standard as an appropriate standard for mercury for non-continental units, analogous to their conclusion for the Gas 1 subcategory.

3. The regulation establishes a numerical emission limit for carbon monoxide (CO) of 160 ppm by volume on a dry basis corrected to 3 percent oxygen for existing units and 51 ppm by volume on a dry basis corrected to 3 percent oxygen for new units. Compliance is demonstrated by an initial CO performance test and continuous monitoring of the oxygen content of the unit exhaust gas versus an O_2 parameter established during the CO performance test.

Stack O_2 measurements, as apparently required by specifying that the analyzer be in the "exhaust gas," are not always the best indicator of CO and organic HAP emissions because they are influenced by air leakage into the unit. This is a particular concern for process heaters, because they typically have many more potential leak locations than does a boiler and because they often run at a negative pressure. Thus, in many cases existing O_2 monitors are located in the radiant section roof or at another location as near to the firebox as possible, considering sensor temperature constraints and the need for safe access for testing and maintenance while the boiler or process heater is in operation. The regulation should allow flexibility in locating the O_2 analyzer, as long as a representative location is selected, since every boiler and process heater is designed and operated differently. The regulation language should be clear that this is a modification from, and overrides, the location specification in Part 60 Performance Specification 3, which has a different purpose (i.e., determining stack gas O_2 for the purpose of correcting measured stack emissions to standardized O_2 levels.)

Additionally, the regulation should allow the use of CO analyzers or Total Combustibles analyzers as an alternate to oxygen analyzers, since some units already have such analyzers. While O_2 monitoring will provide continuing compliance assurance at the most reasonable cost, direct measurements should be allowed where the instrumentation already exists.

4. The regulation establishes a numerical emission limit for dioxins/furans (D/F) of 4 ng/dscm (TEQ) corrected to 7 percent oxygen for existing units and 0.002 ng/dscm (TEQ) corrected to 7 percent oxygen for new units. As with PM, there was no test data from non-continental units for D/F available to the Agency; thus, the limit for the Non-Continental Liquids Subcategory was set equal to the limit derived for the Continental Liquids Subcategory.

In the proposed Electric Utility NESHAP rulemaking[3], EPA concluded that "The significant majority of measured emissions from EGUs of these HAP were below the detection levels of the EPA test methods, and, as such, EPA considers it impracticable to reliably measure emissions from these units. As the majority of measurements are so low, doubt is cast on the true levels of emissions that were measured during the tests. Overall, 1,552 out of 2,334, total test runs for dioxin/furan organic HAP contained data below the detection level for one or more congeners, or 67 percent of the entire data set. In several cases, all of the data for a given run were below the detection level; in few cases were the data for a given run all above the detection level." A work practice standard (unit tune-ups) was therefore proposed to address D/F under the authority of Section 112(h) of the Clean Air Act (CAA). A similar conclusion was reached in that proposal for organic HAP. In that case EPA concluded that "For the non-dioxin/furan organic HAP, for the individual HAP or constituent, between 57 and 89 percent of the run data were comprised of values below the detection level. Overall, the available test methods are technically challenged, to the point of providing results that are questionable for all of the organic HAP. ... Based on the difficulties with accurate measurements at the levels of organic HAP encountered from EGUs and the economics associated with units trying to apply measurement methodology to test for compliance with numerical limits, we are proposing a work practice standard under CAA section 112(h)."

We believe the D/F dataset for liquid-fired boilers and process heaters demonstrates the same problems as the Electric Utility dataset demonstrates for D/F and for organic HAP and that, therefore, the standard for D/F under the Boiler and Process Heater NESHAP should also be a work practice (e.g., a tune-up work practice as is proposed for electric utility units).

[3] 76 Fed. Reg. 24976, May 3, 2011

The dataset used to establish the BPH Liquid D/F limit, and thus the non-continental liquid D/F limit, is comprised of data from 13 continental sources. Two sources comprised the top 12% of this dataset and thus were the basis for the MACT floor determination. As shown in Appendix D-3 of the floor analysis[4], for one of the floor units all 51 measurements of individual D/F compounds were non-detects. For the other unit, 31 of 51 individual D/F compounds were non-detects. Thus, the D/F limit for liquid fired units in the stayed rule is based on data in which only 20 of 102 measurements detected the D/F compound being measured. This 20% rate is lower than the 33% D/F detection rate that EPA considered impracticable to reliably measure emissions from electric utility units and consistent with the 11 to 43% detection rate for organic HAP that EPA also concluded made it impractical to measure for electric utilities.

As with electric utility units, it is likely that D/F formation is inhibited by the high sulfur to chlorine ratios in the liquid subcategory fuels[5]. Thus, as EPA found for the electric utility boilers, the very low generation of D/F and the difficulty of measuring D/F emissions from boilers and process heaters firing liquids would be expected to continue, even if additional data is gathered.

5. The definition of "unit designed to burn liquid fuel" in the stayed rule specifically notes that "Gaseous fuel boilers that burn liquid fuel during periods of gas curtailment or gas supply emergencies of any duration are also not included in this definition." The driver for this exclusion appears to be based solely on continental units preferentially burning natural gas delivered via a pipeline, except when unavailable, and allowing such units to remain under the "unit designed to burn gas 1 subcategory." This exclusion qualifier, while appropriate for continental units, does not take into account similar non-continental facility restraints. Although non-continental facilities do not have access to natural gas pipelines, many non-continental units are subject to a comparable situation – they preferentially burn gaseous fuel, but utilize liquid fuel when there is insufficient availability of the gaseous fuel. For example, a boiler or process heater at a non-continental refinery may primarily fire refinery gas, but also fires fuel oil when the refinery gas supply is insufficient, such as during production unit turnarounds at the refinery. This is analogous to continental gaseous fuel units firing oil during periods of natural gas curtailment. However, the stayed rule does not provide this exclusion from the "unit designed to burn liquid fuel that is a non-continental unit" subcategory. We request EPA provide a similar exemption for non-continental gaseous fuel boilers and process heaters. The following text is suggested to be added to the "unit designed to burn liquid fuel that is a non-continental unit" subcategory definition:

> *Non-continental boilers and process heaters that preferentially burn natural gas, refinery gas, and/or other gas 1 fuels when available but burn liquid fuel at less than 50% of the annual heat input to the unit when natural gas, refinery gas, and/or other gas 1 fuel availability is insufficient are not included in this definition.*

[4] Docket ID: EPA-HQ-OAR-2002-0058-3273.4

[5] See discussion in Electric Utility NESHAP proposal at 76 Fed. Reg. 25023 (May 3, 2011)

6. In addition, EPA needs to address the annual stack testing requirement. It is a massive undertaking for non-continental refineries to perform tens of stack tests every year, given that stack testers must be brought in and samples often must be shipped to far off mainland laboratories. One solution would be to allow sources to skip stack testing if they are willing to continue to meet the continuous compliance parameter established previously. It would seem that a minimum oxygen level established in an initial performance test would remain a good indicator of good combustion (low CO and particulates) indefinitely.

If you have any questions on these comments, please contact Matt Todd at (202) 682-8319.

Sincerely,

/s/

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Attachments