



North Carolina Department of Environment and Natural Resources

Division of Air Quality

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August 4, 2011

Docket No. EPA-HQ-OAR-2009-0234 and EPA-HQ-OAR-2011-0044
Environmental Protection Agency (EPA)
Mailcode: 2822T
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Subject: Comment Submittal on the Proposed Rulemaking – National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units

Dear Sir/Madam:

The North Carolina Division of Air Quality (NC DAQ), within the Department of Environment and Natural Resources (DENR), appreciates the opportunity to provide comments on the subject proposed rules published in the *Federal Register* on May 3, 2011 (76 FR 24976). The Clean Air Act (CAA) requires the Environmental Protection Agency (EPA) to set national hazardous air pollutants (HAP) emissions standards for major stationary sources based on the maximum achievable control technology (MACT) performance. In turn, EPA then delegates its authority to state and local air quality agencies to implement and enforce the MACT rules.

North Carolina is one of the largest electricity-from-coal states in the US with a 13 Gigawatt capacity from nearly 20 facilities to be affected by the proposed rules. In 2002 North Carolina became the first state to pass a statute resulting in significant emission reductions for criteria air pollutants (CAP) and hazardous air pollutants (HAP) from coal-fired power plants. In response to the statute, most of the large boiler units are in the final stage of being equipped with wet flue gas desulfurization (wFGD) scrubbers and advanced emission controls for nitrogen oxides (NOx). Such technologies originally designed to control CAP emissions also reduce HAP for acid gases, metals, and mercury. As you know, the science in understanding the drivers, inter-relationships, and tradeoffs between CAP and HAP emission control performance is new and evolving. Industry and regulators are still learning what is achievable in maximizing CAP and HAP emission control performance on a continuous basis.

The NC DAQ supports many aspects in the proposed Electric Generating Unit (EGU) MACT and appreciates the challenge EPA faces in considering comments to reach a final decision. We are primarily concerned with the coal-fired EGU MACT emission and compliance related issues, HAP

and CAP measurement data quality, implementation of certain provisions in the rule, and the resulting public health effects. We respectfully submit the following comments.

1. Whether it is appropriate and necessary to regulate EGU HAP under Section 112.

EPA has shown that power plants are the dominant emitters of mercury (50%), acid gases (more than 50%), and many toxic metals (more than 25%) in the United States. Despite the availability of proven control technologies, and the 20-plus years since the 1990 CAA Amendments passed, there are still no existing federal standards that require power plants to limit HAP.

Similarly, based on recent emissions inventory data, coal-fired EGUs account for the highest percentage of certain toxic air pollutant emissions in North Carolina, as illustrated by the following estimates:

- 75% for mercury (Hg),
- 90% for hydrogen chloride (HCl), and
- 96% for selenium, 70% for arsenic and beryllium, and 30% for cadmium.

Given these significant contributions of the EGU sector to toxic emissions both nationally and in North Carolina coming, NC DAQ believes it is appropriate and necessary to regulate EGU HAP under Section 112 of the Clean Air Act Amendments, Section 112.

2. Proposed sub-categorization approaches

EPA has proposed several sub-categories in the rule within the EGU sector. For those units in North Carolina subject to the EGU MACT, each would fall into the sub-category of *Existing coal-fired unit designed for coal greater than 8,300 Btu/lb*. NC DAQ believes the proposed sub-categorization presented in Table 10 of the proposed rule is appropriate and reasonable.

3. Compliance time extension and adequacy of 3-year schedule with 1-yr extension.

There will be hundreds of existing units subject to the EGU MACT that will need to be retrofitted with new or modified, large-scale, custom-engineered air pollution control equipment, including:

- a. Dry flue gas desulfurization (FGD) and dry sorbent injection (DSI) systems for acid gas control,
- b. Electrostatic precipitators (ESPs) and fabric filters (FFs) for particulate matter (PM) control,
- c. Activated carbon injection (ACI) systems for Hg control,
- d. Continuous emission monitoring systems (CEMS) for PM, acid gases, and Hg, and/or
- e. Instrumentation and controls for the above.

The scale of such engineering and construction work for an EPA estimate of \$50 billion would be a challenge within a 3-4 year time period even during normal workload conditions. But when competing demand for an adequate supply of experienced workforces and specialized equipment (e.g., large-scale cranes) for hundreds of EGUs is taken into account, there is a strong basis for concern for a resource (workforce and equipment) shortage. In addition, the Industrial Boiler (Boiler) MACT is expected to create its own resource during the same time period and further exacerbate the EGU MACT resource shortage situation.

After a new rule is promulgated, the owner must evaluate APC adequacy to determine whether additional controls are required in response to the rule. Then it can take over 3 years to install and startup EGU-scale APC equipment after the facility has the necessary permits, specifications completed, and a contractor secured before it can commence construction. These steps could easily add several additional months. Total project length including these other factors could be 42 months.

Given the extent and availability of resources required for the EGU and Boiler MACTs, NC DAQ is concerned with the adequacy of the 3-year compliance schedule with a 1-year extension. NC DAQ suggests EPA grant the 1-year extension in the final rule and also consider whether other provisions to grant additional time are justified.

4. Facility-wide Emission Averaging.

Emissions averaging would allow facilities to demonstrate compliance by averaging individual units emitting above the limits with other *sister* units at the same facility emitting below the limits within the same subcategory. This would represent an equivalent, more flexible, and less costly alternative to controlling certain emission points. Provided it follows the proposed weighted averaging approach, it would not lessen the stringency of the MACT limits. Given the constraint for averaging only between sister units within the same category, NC DAQ does not support the application of any emission discount in averaging. NC DAQ agrees the final rule must ensure any emissions averaging option can be implemented and enforced, and an averaging plan is required to be prepared that will be clear both to sources and their permitting authority.

Towards that end, NC DAQ recommends EPA provide further clarity and definition in the final rule on emission averaging. NC DAQ recommends EPA develop an emission averaging certification mechanism within the Notice of Compliance Status (NOCS). The NOCS process is established, and states have experience implementing it. Alternatively, we recommend EPA develop a partnership with EGU industry and air pollution control (APC) equipment supplier trade groups to prepare examples on an emission averaging methodology for inclusion in a guidance document illustrating the principles and techniques used to address the following emission issues on conducting averaging:

- During the initial 12-month period following the initial compliance date.
- During and after unit outages.
- During outages of CEMS and other emission measurement alternatives.
- During other complicating circumstances.

5. Startup, Shutdown, Malfunction

As a result of the Court decision¹ vacating the portion of the regulations exempting major sources from NESHAP during periods of startup, shutdown and malfunction (SSM), sources must now comply with CAA section 112(d) emission standards at all times, including SSM. Accordingly, EPA proposed EGU MACT emission standards to apply at all times, and proposed an affirmative defense requirement for malfunctions. EGU units generally startup using either natural gas or oil, and EPA proposed a default diluent value of 10% oxygen or the corresponding fuel specific carbon dioxide concentration for calculating emissions during startup or shutdown.

EPA narrowly defines malfunction in 40 CFR 63.2 as a “sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner...” EPA determined malfunctions should not be viewed as a distinct operating mode, and emissions occurring at such times do not need to be factored into MACT standards. EPA is proposing an affirmative defense to civil penalties for exceedances of emission limits caused by malfunctions and proposing other regulatory provisions to specify the elements to establish this affirmative defense; *i.e.*, the source must prove by a preponderance of the evidence it has met all of the elements set forth in section 63.10001. The criteria ensure the affirmative defense is available only where the event causing an exceedance meets the definition of

¹ In *Sierra Club v. EPA*, 551 F.3d 1019 (DC Cir. 2008),

malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and/or careless operation). The criteria also ensure steps are taken to correct the malfunction, minimize emissions, and prevent future malfunctions.

NC DAQ is supportive of the proposed SSM definitions and procedures.

6. Continuous Emission Monitoring Systems (CEMS) for Mercury, Hydrogen Chloride, and Sulfur Dioxide

NC DAQ supports the application of CEMS for Hg, hydrogen chloride (HCl) and/or sulfur dioxide (SO₂) as emission compliance monitors for enforcement purpose in the rules. In particular:

- NC DAQ believes it is unnecessary to make a modification to the Emissions Collection and Monitoring Plan System (ECMPS) to disable the Part 75 bias test (which is required for certain types of monitors under EPA's emissions trading programs) for Hg and HCl (or SO₂), since the bias test is primarily tied to emissions trading, which is not part of this rule.
- The proposed rule does not require the use of missing data substitution for Hg monitoring systems and intends to extend this concept to HCl and PM CEMS. Hours when a monitoring system is out of service would simply be counted as hours of monitor down time, to be counted against the percent monitor availability. Since data substitution is primarily tied to emissions trading, NC DAQ agrees that it is unnecessary in this rule.
- The EPA proposed a "one-stop shopping" approach to reporting MACT compliance data electronically. The EPA requested to consider the merits of requiring reporting of results from PM CEMS and HCl CEMS to ECMPS and consequent development of a monitoring and reporting scheme for these CEMS compatible with ECMPS. NC DAQ supports the proposed approach for electronic reporting. By using a successful, familiar, and standardized data system like ECMPS, it will be less burdensome than creating a different electronic approach.
- NC DAQ supports the facility's option of using SO₂ CEMS in place of an HCl CEMS, since a relationship can be derived to convert an HCl limit to a SO₂ limit, and because SO₂ CEMS are already in place at all affected EGU facilities in North Carolina.
- NC DAQ encourages EPA to expedite its schedule for developing a low level Hg generator/calibrator in the range of 1 microgram per cubic meter (ug/m³) suitable for Hg concentrations in the range of the proposed standard (nominal 1.5 ug/m³).

7. EPA Should Clarify Representative Operating Conditions and Maximum Normal Operations

Section 63.1 0009(e) in the rule requires performance tests to be conducted at "maximum normal operating load."² However, section 63.1 0009(g)(2)(vii) requires a demonstration of compliance with each of the applicable emission limit(s) to be achieved under "representative operating conditions."³ EPA needs to clarify this discrepancy and clearly define in section 63.10042 what constitutes maximum normal operating load and/or representative operating conditions.

8. Transitioning From Boiler MACT/GACT to EGU MACT

The rule's preamble discusses the following scenario:

[T]here will likely be some cogeneration units that are determined to be covered under the Boiler MACT/GACT. Such units may make a decision to increase/decrease the proportion of production output being supplied to the electric utility grid, thus causing the unit to meet the EGU cogeneration

² 76 FR at 25108.

³ Id. at 25110.

criteria (i.e., greater than one-third of its potential output capacity and greater than 25 MWe⁴). A unit subject to the Boiler MACT/GACT that increases its electricity output and meets the definition of an EGU would be subject to the EGU MACT for the 6-month period after the unit meets the EGU definition. Assuming the unit did not meet the definition of an EGU following that initial occurrence, at the end of the 6-month period it would revert back to being subject to the Boiler MACT/GACT.⁵

EPA solicits comment on the extent to which this situation might occur and whether the 6-month period is appropriate. There are cogeneration units in North Carolina that could potentially follow the above-mentioned scenario. EPA did not address the regulatory logistics on how this would be implemented. We request EPA provide in the final rule a clear process to demonstrate initial and continuous compliance for cogeneration units that may change Section 112 applicability. This process needs to provide the specific period or deadline when the cogeneration unit stops compliance with the Boiler MACT and starts complying with the EGU MACT and vice versa, to include notification requirements when changing rules, and to specify testing and NOCS deadlines.

In addition, the EPA should address how the "once-in-always-in" policy applies to sources subject to the Boiler MACT that become subject to the EGU MACT when the source meets the EGU cogeneration criteria.

9. Transitioning From CAA Section 112 to Section 129.

EPA solicited comment on whether the rule should include provisions similar to those in the final CISWI rule⁶ to address units that combust different fuels at different times. A few EGUs in North Carolina have the potential to combust materials that could be considered solid waste under the proposed RCRA definition. These are EGUs that do not meet the exemption under CAA section 129 (g)(1)(B) for qualifying small power production facilities or qualifying cogeneration facilities. NC DAQ recommends the EPA include provisions similar to those included in the final CISWI rule to address units that combust different fuels at different times.

10. APC operating parameters to demonstrate ongoing compliance.

A. The rule proposes that facilities "monitor during initial performance testing specified operating parameters that you would use to demonstrate ongoing compliance."⁷ In the final rule we suggest it should be clearly stated:

i. When CEMS are used for emission monitoring, APC operating parameters limits (OPLs) only need to be well documented and are not required to be established as OPL s; and

ii. Only when CEMS are not used for emission monitoring is there a need for key APC OPLs to be established during compliance testing.

B. The proposal identified wet FGD scrubber pressure drop and liquid flow rate as the APC performance indicators for acid gas compliance purpose and testing in several places. We are familiar with pressure drop and liquid flow rate for *venturi* scrubbers being established as APC performance indicators for PM control. However, we are not familiar with any evidence that wet FGD scrubber pressure drop serves as a performance indicator for acid gas removal. We request that EPA:

⁴ MWe = Megawatt electric (output)

⁵ *Ibid.* at 25026.

⁶ Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units, 76 Fed. Reg. 15704 (March 21, 2011).

⁷ Federal Register, Vol. 76, No. 85, Proposed EGU MACT Rule, p. 25029.

- i. Provide evidence FGD scrubber pressure drop is a suitable APC performance indicator for acid gas (or PM) removal.
- ii. If such evidence cannot be provided, we suggest EPA work cooperatively with the utility industry and FGD supplier trade groups to characterize available scrubber technologies in terms of their design, performance, operating parameters, and cost for acid gas, filterable PM, and condensable PM control.
- iii. Alternately, the rule could allow facilities to develop site-specific plans for measurement of factors that more accurately account for indicating APC equipment performance than those EPA proposed. Facilities could elect, and demonstrate to the satisfaction of the permitting authority, the use of key APC operating parameters and/or other measurements to indicate APC equipment performance and emissions.

11. Proposed Regulation of Filterable PM and Condensable PM

EPA requested comment on whether separate or combined filterable PM (FPM) and condensable PM (CPM) emission standards would be appropriate and what their numerical values should be. Since the mid-1970s EPA treated PM in a manner consistent with its rule policy -- as that being defined as finely-divided solid or liquid material measurable by Method 5 or its equivalent.⁸ The MACT EGU rule proposed two new pollutants:

1. Condensable PM (CPM), defined as vapors or gases under stack conditions that form solids or liquids upon release to the atmosphere as measured by the revised Method 202; and
2. Total PM, defined as *filterable* PM plus *condensable* PM, and set a total PM emission limit of 0.03 lb/MM Btu.

EPA concluded the best approach to reduce emissions of both FPM and CPM was to establish a total PM standard, rather than setting separate standards for each. FPM is to serve as a surrogate for ten non-Hg metals, while CPM would serve as a surrogate for sulfuric acid mist (H₂SO₄) and sulfur trioxide (SO₃), and one non-Hg metal, selenium. Selenium, like mercury, is a volatile metal HAP with unusual properties for EGU emission control since it can be emitted as both particles and vapors, and adsorbed onto PM. In addition, this rule would advance the control of selenium (Se), as it is the most EGU emissive metal, accounting for 36% of the total of the ten regulated metals.⁹ Selenium is emerging as a toxin of concern for EGU air and water emissions as well as coal mining. Selenium, H₂SO₄, and SO₃ are indicated to be key contributors to EGU CPM.

Controls for FPM are well established, as an ESP or FF can control both coarse and fine FPM. In contrast, CPM controls are much less developed. EGU CPM is composed primarily of SO₃ and H₂SO₄, but may also contain smaller amounts of nitrates, halides, ammonium salts, and volatile metals such as mercury and selenium. Controls EPA expects to reduce emissions of CPM include lower sulfur coals, selective catalytic reduction (SCR) catalyst or other NO_x control device with minimal SO₂ to SO₃ conversion, FGD scrubber, alkaline dry sorbent injection (DSI) upstream of a PM control, and a wet ESP. Other controls such as FFs or ESPs may also provide some reduction in CPM—depending largely on flue gas / fly ash composition and temperature. However, other control options appear limited to further reduce the CPM fraction as operating the PM control at a cooler temperature is not a practical option due to corrosion concerns, and existing ductwork might not make DSI viable without major flow or ductwork modifications.

⁸ EPA was silent on the term and concept of condensable PM in the Industrial Boiler MACT Rule, promulgated March 21, 2011, accessed <http://www.epa.gov/ttn/atw/boiler/boilerpg.html>, on June 20, 2011.

⁹ Ten metals are antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

In terms of proposed monitoring for total PM, a PM CEMS would be used for FPM with a representative site-specific CEMS value derived from the compliance test conducted every 5 years to serve as an ongoing FPM operating limit (presumably a compliance assurance monitoring-type limit).¹⁰ For CPM, only the Method 202 test conducted every 5 years would serve to evaluate or indicate compliance, as no monitors, operating parameters, or surrogates were proposed in the rule.

NC DAQ began studying CPM in the late 1990s and issued guidance requiring CPM emission measurement whenever sources were tested for PM. CPM contain HAP and account for actual emissions that eventually transform into PM after release to the atmosphere, thereby providing a realistic account of total emissions for modeling ambient concentration of PM and other pollutants.

EPA requested EGUs, included several in North Carolina, to provide toxic emission data in the 2010 MACT Information Collection Request (ICR) after revising Method 202. Most of the NC tests were conducted at units burning higher sulfur eastern bituminous coals with flue-gas-desulfurization (FGD) scrubbers installed in recent years. The ICR data indicated CPM and FPM emissions were each measured across the same range for NC utilities: 0.004 - 0.01 lb/MM Btu with few data showing CPM up to twice FPM levels for scrubbed units preceded by ESPs. Review of the ICR data indicates CPM is also in the same range as CPM data from the early 2000's before FGDs were installed. What seems much lower is FPM. It may not be CPM has increased so much as the FPM has decreased. While some studies have occurred recently, there appears to be much variability and uncertainty about understanding the composition and control of CPM emissions. New rules would tend to promote a better understanding of CPM emission behavior and control.

We support the use of PM CEMS as a reasonable compliance monitoring option. Limited experience in NC with three light-scattering PM CEMS in wet, post-scrubber operating environments has been favorable, both in the certification process and in continued operation. The PM CEMS met the initial correlation test and ongoing QA requirements, as well as achieved monitor availability of 99+% over 1½-years. The development and use of an aerosol generator/calibrator for audits would simplify the burden on units finding it difficult to adjust emissions in order to meet the ongoing QA requirements.

Based on our review, NC DAQ suggests EPA consider a FPM emission limit and using PM CEMS as a compliance monitor equivalent in use and consequence as SO₂, NO_x, and mercury CEMS, rather than the proposed total PM/CPM approach. The rationale for this suggestion is based on the following points:

1. After 40 years, one can characterize FPM measurement, control, and regulation as mature and well-developed.
2. In contrast, the nature of CPM measurement, control, and regulation is new and not fully formed. The determination of CPM compliance can only be made over a few-hour period once every 5 years. The proposed CPM approach, while the best current technology allows, results in weak and infrequent enforceability.
3. With only a total PM limit approach, the absence of any ongoing CPM emission indicator (monitor, operating parameter, or surrogate) reduces the efficacy of not only CPM emission provisions, but also FPM and total PM provisions.
4. With a FPM limit using PM CEMS as a compliance monitor, FPM compliance enforceability would be strengthened, and the rule's PM emission reductions better assured.

¹⁰ Asking EPA to clarify this point later in this document.

12. Whether both total PM and non-Hg metals testing and compliance are necessary.

Metal HAP emissions are a tiny component of total PM (0.12% on average)¹¹, and are expected to be reduced along with PM as a result of application of better emission controls. EPA is proposing to use total PM as a surrogate for ten non-Hg metal HAP emissions. However, the proposal contains apparently conflicting statements on testing and compliance requirements; some sections state emissions from both (total PM and non-Hg HAP metals) would be required to be measured and to be complied with their respective limits, while other sections could be interpreted as indicating there is a choice between testing/meeting either separately, as illustrated below.

- A. The proposal states “For coal-fired units,... if you elect to comply with the total PM emission limit, then you would conduct HAP metals and PM emissions testing during the same ... test period and under the same ... operating conditions initially and every 5 years [thereafter] using EPA Methods 29, 5, and 202.” (see page 25029)
- B. However in Tables 1 and 2 to Subpart UUUUU of Part 63, the proposal states under the column “For the following pollutants... Total PM... OR Total non-Hg metals ... OR (Ten) Individual metals.” This language indicates there is a choice between testing/meeting total PM or non-Hg HAP metals provisions separately. (see page 25124-25128)
- C. “EPA is under no obligation to achieve a particular numerical reduction in HAP metal emissions. We have considered this case in evaluating whether the surrogate standards we propose to establish in this proposed rule are reasonable.” (see page 25021)

On related practical issues, if both limits were to apply, what would a facility do in the event that it met the PM limit but did not meet the total metals limit or any of the individual metals limits? On the other hand, if the metals emission limits were derived in such a conservative fashion as never to be exceeded when the PM limit is met, then why even propose metals emission limits and metals emission testing?

In summary, we are asking EPA whether both total PM and metals testing required during compliance tests to:

- i. Show compliance with non-Hg metals HAP limits once every 5-years, and
- ii. Establish the basis for the correlation between PM and non-Hg metals so that PM can be used as a surrogate for continuous compliance for non-Hg metals?

13. To what extent and for what purpose would PM CEMS be used:

- i. **Only as a parameter monitor in setting a unit-specific operating limit, or**
- ii. **As an emission limit compliance monitor?**

The proposed rule states that ongoing compliance would be determined using a PM CEMS with an operating limit established based on the *filterable* PM [CEMS] values measured using Method 5 during compliance testing. Such language and purpose using a FPM CEMS with an operating limit is distinct from the Hg and HCl/SO₂ CEMS proposed for a more rigorous purpose as an emission compliance monitor. The FPM CEMS measures only the filterable portion of total PM (hereafter PM CEMS will be referred to as FPM CEMS to clarify it measures only FPM). Use of a CEMS as a compliance monitor has stronger legal leverage and consequences than using a CEMS as an operating limit parameter. Given the eventuality of some facilities exceeding their FPM CEMS operating limit, what is the expected consequence for a facility exceeding its FPM CEMS operating limit, and what would happen if the FPM CEMS level indicated the FPM was above the total PM emission limit? We request these points be addressed and clarified in the final rule.

¹¹ EPA MACT Floor Analysis - Coal HAP Metals MSEXcel file, accessed June 15, 2011 at <http://www.epa.gov/airtoxics/utility/utilitypg.html>,

14. Enforcement shield for FPM CEMS correlation tests.

The proposed rule requires FPM CEMS to be pre-certified prior to the initial compliance test. As an integral part of the certification, a procedure of correlating FPM CEMS responses relative to emission concentrations determined by the reference method must be completed. This requires deriving the primary mathematical relationship for correlating FPM CEMS output to a FPM concentration, as determined by the reference method. Before certifying FPM CEMS, Performance Specification 11 (PS 11) directs facilities to observe FPM CEMS response over time during normal and varying process conditions to ensure it was set up to operate over a wide operating range. It further states to select a FPM CEMS capable of measuring the full range of FPM concentrations expected “*from normal levels through the emission limit.*” Conducting correlation tests going through the emission limit presents a scientific and regulatory dilemma, particularly during the initial correlation test when the FPM CEMS level corresponding to the emission limit is likely an unknown quantity.

The scientific dilemma is one of a circular reference, in which the unknown FPM CEMS value at the emission limit is required to be known in order to calculate the FPM CEMS value at the emission limit. To exacerbate the situation, the emission limit is a level never to be exceeded, or when exceeded, there would be serious financial penalties. This is where the regulatory dilemma comes in. On one hand PS 11 advises facilities to conduct correlation at or beyond the emission limit. But on the other hand, PS 11 or the EGU MACT rule does not provide protection from unknowingly exceeding the limit while acting in good faith when following EPA’s guidance to test “*from normal levels through the emission limit*” during correlation tests. Facilities would not know how close the limit was approached or exceeded *until after* the correlation tests were completed.

As written, PS 11 or the EGU MACT rule does not provide a legal shield to protect facilities against exceeding the emission limit when following EPA guidance during the correlation test. To resolve this, we urge EPA to provide some explicit form of a legal shield by revising PS 11 and (at least referencing such in the EGU MACT rule) to protect facilities against this situation. We suggest the shield be in the form of stating the *FPM standard does not apply during FPM CEMS correlation tests for a specified time period as pre-approved by the permitting agency.*

15. Whether both total HCl and/or SO₂ testing and compliance are necessary.

There is another case where there can be some confusion on the issue of testing/complying with emission standards, but this time with HCl using SO₂ as a surrogate. The proposal contain apparently conflicting statements; some sections state emissions from both acid gases (HCl and SO₂) would be required to be measured and to be complied with their respective limits, but other sections could be interpreted as indicating there is a choice between testing and complying with each acid gas emission limit separately. On a practical basis, if both were to apply, what would a facility do in the event that it met the SO₂ limit, but did not meet the HCl limit?

A. The proposal states “For coal-fired ... that have SO₂ emission controls and elect to use SO₂ CEMS for continuous compliance, an initial stack test for SO₂ would not be required. Instead the first 30 days of SO₂ CEMS data would be used to determine initial compliance. (see page 25029)

B. However in Tables 1 and 2 in Subpart UUUUU, the proposal states under the column “For the following pollutants... the stated information – “HCl OR SO₂ “ -- would indicate there is a choice between testing/meeting HCl or SO₂.

16. Agency Resource Burdens for Emission Testing Requirements

Compliance workload (observing emission tests, reviewing protocols and reports, certifying PM and Hg CEMS) associated with the proposed EGU MACT could greatly increase while permitting authorities will not be able to add staff to meet this new workload. Requiring sources to conduct

comprehensive testing without agencies being able to adequately monitor testing is ineffective. We suggest once the initial performance test is conducted for regulated HAP emissions, and fuel sampling and/or operating parameters are established, fuel sampling would be a simpler approach than requiring excessive emission testing. The burden will move to the source owner without agency staff being available to witness the numerous performance tests required.

Another approach would be for EPA to consider revising the monthly and bimonthly testing requirements to quarterly or biannual requirements in order to provide a reasonable schedule to maintain quality and review procedures. We also suggest compliance margin be tied to testing frequency; for example, once a unit has successfully demonstrated emissions at less than 70% of a standard for a few consecutive times, testing frequency would be reduced.

17. Development of EGU MACT Materials for Agency Training

EPA and other agencies have published documents which characterize emission controls for industrial source categories for air quality agencies.^{12,13} Control techniques documents (CTDs) provide practical and technical information for agencies to implement rules (such as MACTs) requiring EPA approval. DAQ suggests EPA prepare a CTD or offer equivalent guidance for the APC technologies identified in the EGU MACT. A CTD would serve an essential role in assuring state/local agencies are adequately informed in order to understand and enforce how EGUs would comply with this complex multi-HAP rule. Information in the CTD would characterize several control technologies and cover key aspects of each as outlined below:

APC technologies

- a. Combustion controls, fluidized beds, coal types, halogen spraying
- b. Post-combustion controls: SCR, SNCR
- c. ESPs, Wet ESPs
- d. FFs -- EGU bag types
- e. Wet PM (venturi) scrubbers
- f. Wet acid gas (FGD) scrubbers – Forced-oxidation limestone, magnesium-enhanced
- g. Spray dryers (dry FGD scrubber)
- h. Dry sorbent injection –hydrated lime, trona, sodium carbonate/bicarbonate
- i. Activated carbon injection – conventional, brominated

Key aspects covered for each APC technology:

- Design/controls/equipment/parameters impacting emissions;
- APC performance principles, parameters/normal range/monitors, upgrades;
- Multi-pollutant aspects, co-benefits of APC performance.

We request EPA address and clarify these issues in the final rule.

¹² Similar to EPA “Alternative CTD Update – NOx Emissions from New Cement Kilns,” EPA-453/R-07-006, Nov 2007.

¹³ Similar to NESCAUM, “Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants,” March 2011.

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We sincerely appreciate your consideration of these comments. If we can be of assistance regarding these comments, please contact Mr. Steve Schliesser of my staff at 919-715-2694 or at steve.schliesser@ncdenr.gov.

Sincerely,



Sheila C. Holman
Director, Division of Air Quality

SCH/ss

c: Robin Smith, Assistant Secretary for Environment

