

The Proposed Combustion Turbine (CT) and Industrial
Boiler (IB) MACT Rules
The Potential Impact on the Utility Industry

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Introduction

The Environmental Protection Agency (EPA) has recently proposed two new regulations that potentially have significant impact on the utility industry. These new proposed rules are the stationary combustion turbine (CT) MACT rule and the industrial boiler (IB) MACT rule. The MACT rules are designed to reduce the emissions of hazardous air pollutants (HAP) from various sources. MACT rules can effect existing as well as new sources. The emission limitations are technology based so the limitations may be different for various source categories within a broad spectrum. The MACT process is very complex and it is not unusual to have a number of subcategories of sources with different emission limits and compliance procedures. For example, the proposed CT MACT rule contains six subcategories of sources. The CT MACT rule will directly impact all new utility CTs and some existing CTs. The IB MACT rule has little impact but we are interested in its construction because it may set the stage for the pending utility boiler MACT. This paper focuses on the CT MACT because of its immediate impact.

The regulatory picture is not pretty because EPA seems to be rushing these MACT rules out the door with little thought or analysis. There are serious problems with both proposals and perhaps EPA will take the time to read the comments and correct some of the more egregious errors. Will the final rules be reasonable and workable? Perhaps - but the cost will be high in terms of both dollars and manpower.

The CT MACT

The proposed CT MACT rule effects all new electric utility CTs (both diffusion flame and lean burn) and existing lean burn CTs. It does not effect existing diffusion flame CTs. Unfortunately, this raises an important issue - what is to be done with existing dual fuel machines that operate in both modes? Is a dual fuel unit only an effected unit when it is operating in lean burn mode? The rule regulates formaldehyde emissions as a surrogate for all HAPs.

The rule states that an effected unit can comply with the rule in one of two ways. It can install an oxidation catalyst and demonstrate a 95% reduction in CO emissions using continuous emissions monitoring (CEM) for CO before and after the catalyst.¹ The second method is that the source can comply with a formaldehyde limit of 43 ppb @ 15% excess O₂. EPA assumes that a diffusion flame CT will have to use the oxidation catalyst to achieve the 43 ppb limit and that the lean burn machine will not have to use a catalyst. They arrived at this conclusion by reviewing test data from a number of formaldehyde tests.

¹ In this case, CO is assumed to be a surrogate for formaldehyde.

CO Measurement Issues on CTs Equipped with Oxidation Catalyst

As mentioned previously, the EPA has proposed a 95% CO reduction standard as one of the alternative limits for new CTs and specifies that oxidation catalyst will be used to obtain this 95% CO reduction. The compliance method proposed is the measurement of CO emissions (normalized to 15% O₂) prior to the oxidation catalyst compared to a similar CO measurement after the catalyst. The two measurements are then compared and 95% or greater reduction is expected. The proposed rule does not differentiate between simple-cycle CTs and combined cycle CTs. It also does not differentiate between single fuel units and dual-fuel units. Many combined-cycle CTs are dual-fuel units, and the CT can operate on natural gas in the lean burn mode or on No. 2 fuel oil in the diffusion mode. In addition, most combined-cycle units are equipped with auxiliary burners (also called duct burners) that are fired with natural gas. The proposed rule erroneously assumes that the CO emissions reduction from the CT on a combined-cycle unit can be measured independently from the CO emissions from the auxiliary burners on that same unit. This is impossible.

It is impossible because, on a combined-cycle unit, the auxiliary burners are physically located inside the heat recovery steam generator (HRSG) prior to the NO_x reduction catalyst and oxidation catalyst. (Both catalyst beds are also mounted in the HRSG - see Figure 1.) Therefore, any CO produced by the auxiliary burners will also be treated by the oxidation catalyst. A simple example will illustrate the point. Assume that the CT is operating without auxiliary burners and is producing 5 ppm CO. If 95% reduction is achieved the outlet CO concentration will be 0.25 ppm. Now assume that we light the auxiliary burners and they add another 5 ppm CO for a total of 10 ppm. At 95% reduction the outlet CO concentration will be 0.5 ppm. To achieve the "apparent" compliance level of 0.25 ppm level on the outlet will require 97.5% CO reduction across the oxidation catalyst.

Since measurements of the CO contributed by the CT alone cannot be made when the auxiliary burners are operating, the compliance procedure proposed by EPA is impossible to do on combined-cycle units equipped with duct burners.

While not an impossible measurement on combined-cycle units without auxiliary burners or simple-cycle CTs, the differential CO measurement proposed by EPA is very difficult to do on a continuous basis. If one again refers to Figure 1 and ignores the auxiliary burners, the figure depicts a combined-cycle unit without auxiliary burners. While, in theory, the differential CO compliance test is possible to conduct on a combined-cycle unit when there are no auxiliary burners, or a simple-cycle unit, this measurement will be difficult because of the unrepresentative nature of the CT outlet sampling location. The gas in this location is very aggressive - the temperature is 1000 degrees F, the pressure is in the range of 20-40 inches of water and the velocity is hundreds of feet per second. Also, depending on the design of the CT, this flow stream may be highly stratified in terms of CO, O₂ and CO₂ concentration and velocity.

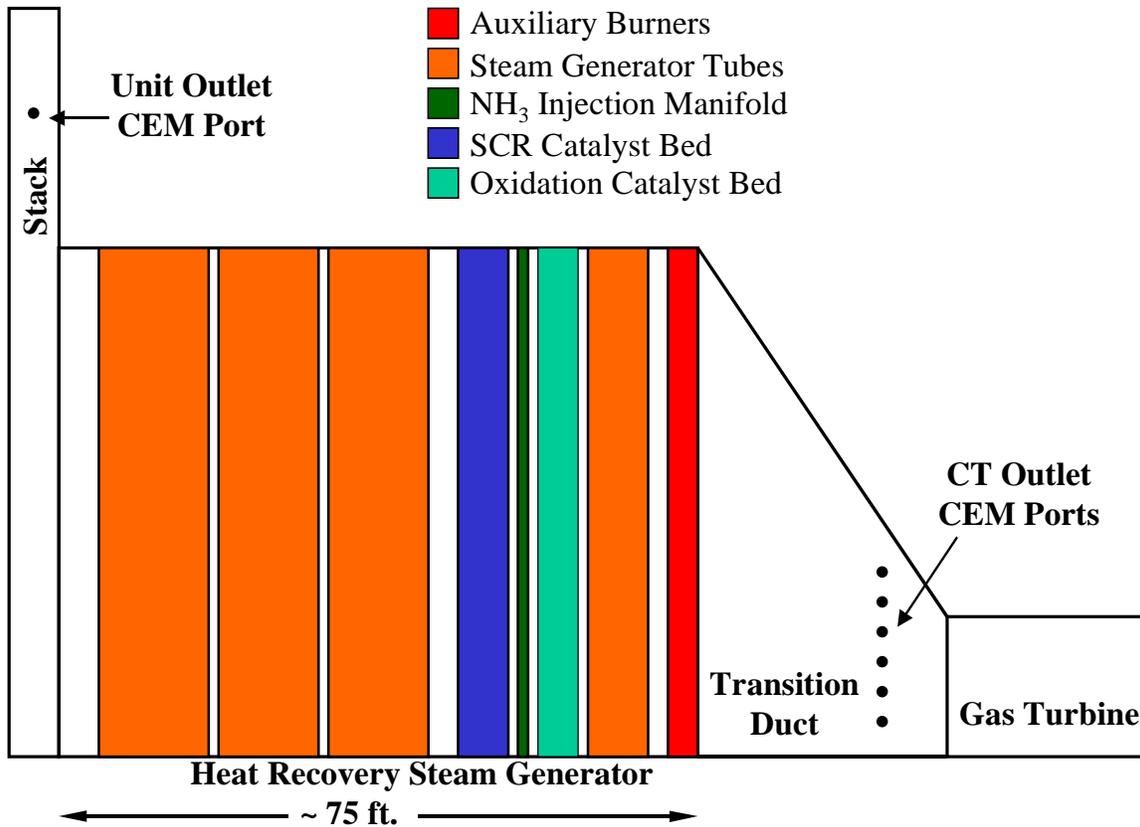


Figure 1. Combined Cycle CT with Auxiliary Burners - Cross Section

If the flow is stratified with respect to CO, O₂, or CO₂, a gas sampling probe matrix containing 16-48 sampling probes must be installed to adequately sample the cross sectional area of the duct.² A balanced flow manifold would have to be designed to ensure balanced flow through all of the probes. In addition, some type of cooling mechanism would have to be designed to cool the gas from 1000 °F down to about 350-400 °F before the sample enters the Teflon sampling line. The sampling system design is a challenging engineering design and fabrication problem that we do not believe has ever been done for a continuous analyzer measurement system. In any event, as will be discussed later, CO analyzers are not available to make the appropriate catalyst outlet CO measurements so the entire concept is unnecessary and futile.

Another point is that the uncontrolled CO emissions from new CTs are extremely low and 95% CO control of new oil fired diffusion flame machines seems to be unwarranted and perhaps impossible. EPA states in the proposed rule preamble that, "diesel-fired combustion turbines cannot be operated in the lean premix mode, and these turbines would have to install an oxidation catalyst system." We are not sure that this statement is accurate because some new oil-fired diffusion flame machines are operating at CO levels

² From a technically correct sampling perspective, the multi-point sampling grid should be designed to sample each point in the gas stream proportional to velocity if there is velocity stratification. As a practical matter, such a sampling system would be virtually impossible to operate and maintain.

comparable to gas-fired lean burn machines. RMB contacted several clients to obtain *uncontrolled*³ CO measurements from initial compliance tests of oil-fired diffusion flame machines. These data are summarized in Table 1 below.

Table 1 - CO Data From New Oil-fired Diffusion Flame CTs							
Unit	Manufacturer	Fuel	Mode	Cycle	NOx Control	Load – Mw	CO - ppm
A	GE-7FA	Oil	Dif	SC	Water	168	0.61
A	GE-7FA	Oil	Dif	SC	Water	150	0.93
A	GE-7FA	Oil	Dif	SC	Water	125	0.74
A	GE-7FA	Oil	Dif	SC	Water	85	0.65
B	GE-7FA	Oil	Dif	SC	Water	170	0.84
B	GE-7FA	Oil	Dif	SC	Water	145	0.46
B	GE-7FA	Oil	Dif	SC	Water	123	1.20
B	GE-7FA	Oil	Dif	SC	Water	85	0.88
C	GE-7FA	Oil	Dif	CC	Water/SCR	167	0.84
C	GE-7FA	Oil	Dif	CC	Water/SCR	141	0.91
C	GE-7FA	Oil	Dif	CC	Water/SCR	110	0.98
C	GE-7FA	Oil	Dif	CC	Water/SCR	75	0.87
D	GE-7EA	Oil	Dif	SC	Water	80	1.79
E	GE-7EA	Oil	Dif	SC	Water	80	5.84

It can be readily seen that the *uncontrolled* CO emissions from these oil-fired, diffusion flame CTs are generally very low and for these modern machines are 1.0 ppm and below. If 95% CO control were to be applied to these diffusion flame machines, the resulting CO emissions would be in the range of 0.02-0.06 ppm CO. As discussed later in this paper, these very low levels of CO emissions are impossible to measure with any level of accuracy using state-of the art CO monitors.

While not included in Table 1 above, it should be noted that RMB also obtained a number of CO test results from gas-fired, lean premix machines and these CO values were, on average, somewhat lower than the oil-fired units. The gas-fired, lean premix CO values ranged from 0.05 to 0.84 ppm. As discussed in the next issue, some of these values are so low they might just be electrical noise or analyzer drift. Of course, there is no way to quantify the accuracy of the data because Method 10 has not been verified at these low CO levels.

A periodic test of the absolute level of CO or formaldehyde emissions should provide an acceptable measure of oxidation catalyst performance on large, modern diffusion flame CTs. It appears that EPA has not fully evaluated CO or formaldehyde emissions data from the most modern, large diffusion flame CTs that would represent the machines most likely to be installed by the electric utility industry. It is possible that these machines are emitting very low levels of formaldehyde even without oxidation catalyst because it is

³ Uncontrolled CO emissions in this discussion means that there is no oxidation catalyst installed on the CT. All of the measurements were taken at the unit stack with Method 10. Since these measurements are very low, we cannot verify the precision or accuracy of the measurements. We can state that the concentrations are very low.

clear that the CO emissions are very low. Even if the diffusion flame CTs do not meet the contemplated formaldehyde limit, they are likely to be well under the limit when an oxidation catalyst is installed.

Therefore, we suggest that an appropriate demonstration of the formaldehyde emissions or the continuing performance of the catalyst would be a periodic CO or formaldehyde test when the unit is operating in diffusion flame mode. A yearly test should be adequate. It should be noted that this approach would also solve the duct burner problem on combined cycle units because the duct burners could be turned off for the duration of the test. This approach would also solve the CO measurement issues discussed in these comments.

Another point is that CO emissions from modern utility CTs are so low they cannot be reliably measured after 95% reduction. RMB obtained the specifications for state-of-the-art *ambient level* CO analyzers from three major monitor manufacturers. Specification sheets were obtained from Thermo Environmental Instruments, Horiba and Advanced Pollution Instrumentation. All of these analyzers are certified by EPA for ambient level CO measurements in air quality measurement networks.

The instruments use either gas filter correlation or non-dispersive infrared analysis techniques. All of these instruments have similar specifications. The MDL is from 0.02-0.04 ppm and the zero drift is from 0.05-0.10 ppm/24 hours. On an electronic measurement system, it is important to recognize that the MDL is only a statistical value, usually defined as three times the standard deviation of the zero noise level. It is also important to recognize that the MDL is determined under stable laboratory conditions, not field conditions. Reliable measurements cannot be made near the MDL since that area is very noisy and very long electronic averaging times must be used to extract any useable signal.⁴ It is generally accepted practice to only make measurements at a level three times the MDL and, even then, such low-level measurements should be used with care because of potential error. Therefore, we suggest that CO measurements below 0.06-0.12 ppm are the absolute minimum level that should be considered valid and that is in a *laboratory environment*. In a field environment, the level would likely be 2-4 times higher (say 0.24-0.48 ppm). Therefore, the oxidation catalyst inlet CO level would have to be in the 5-10 ppm range before one might even consider the possibility of making the 95% reduction measurement.

In addition, the proposed rule states that all CO measurements have to be converted to a constant 15% O₂ basis and the analysis above has not considered the potential error associated with the O₂ measurements. It must also be remembered that a percent CO reduction measurement requires four analyzers (catalyst inlet CO and O₂ analyzer and catalyst outlet CO and O₂ analyzers). The potential errors associated with *all* of the analyzers in a *field environment* have to be considered in evaluating the potential error in the final percent reduction value.

⁴ The TECO Model 48CTL analyzer uses a 300 second averaging time in an attempt to extract a usable signal from the noise.

If one were to conduct a square root of the sum of the squares error analysis using the potential error from four analyzers, it is obvious that the error term will explode. The results of this exercise would be interesting, but it would not be a particularly useful analysis since we do not know the true error terms associated with the field measurements. Unfortunately, EPA has not conducted the work necessary to develop the data to support an analysis of the potential measurement error. It is clear, however, based on only one CO analyzer specification (much less two CO analyzers and two O₂ analyzers), that the 95% reduction requirement cannot possibly be measured unless the oxidation catalyst inlet CO concentration is higher than 5-10 ppm. Frankly, we believe the combined error for a four analyzer monitoring system will be very high and such a system will be essentially unusable.

EPA has also not developed and demonstrated appropriate compliance tests and performance specification tests. EPA states in the proposal that Method 10 and Performance Specification 4 (PS-4) will be modified to allow for CO measurements in the very low ppm range. As we have suggested in the prior discussion, this objective appears to be almost impossible given the very low CO concentrations that will exist after an oxidation catalyst installed on a new CT. Method 10 was developed many years ago and was designed to conduct CO measurements above 20 ppm. Likewise, PS-4 is intended for use on CO continuous emissions monitoring systems that have a monitor range of 0-1000 ppm and PS-4A specifies a monitor range of 0-200 ppm.

Obviously, this research effort should be undertaken by EPA to quantify the single point as well as the differential CO measurement procedure precision and accuracy. One wonders why EPA did not undertake this effort prior to this proposed rulemaking. It should certainly be done prior to rule promulgation. It would seem that EPA needs some level of confidence that the differential CO compliance test method could be performed with a reasonable level of precision and accuracy prior to promulgating its use.

In addition, EPA has not demonstrated that 95% CO reduction can be achieved with oxidation catalyst when the uncontrolled emissions are less than 1 ppm. EPA stated in the proposed rulemaking package that the 95% CO control level requirement came from an oxidation catalyst vendor. Control device vendor statements are notoriously unreliable, and we wonder if there are any data to support a 95% reduction claim when the catalyst inlet CO concentration is in the 1.0 ppm range. In addition, the percent removal of CO across a catalyst will be directly related to the inlet CO concentration. The higher the inlet CO concentration, the higher percent reduction will be achieved given any specific catalyst bed, temperature and velocity through the catalyst. It is simple chemistry and physics. Since CO levels at the outlet of a catalyst with 1 ppm inlet concentration would be extremely low (0.05 ppm) the concentration is essentially impossible to measure accurately and precisely. Therefore, we doubt that such data exist.

Formaldehyde Measurement Issues For Lean Burn CTs

As discussed earlier, the compliance procedure for lean burn CTs, without oxidation catalyst, is to achieve a 43 ppm formaldehyde emission limit. Unfortunately, there are a

number of issues with making this measurement. EPA admits in the proposal that these methods currently do not meet the level of accuracy necessary for the rulemaking. EPA is currently revising Method 320 (40 CFR 63 App A) (FTIR), EPA SW—846 Method 0011 and CARB Method 430. However, EPA has not provided any field test results to serve as the basis for the revisions. Admittedly, some method modifications may be made to methods that do not require field verification; however, since the target emissions for the formaldehyde methods are so low and so susceptible to contamination and interference, field verification is necessary. Furthermore, in the case of proposed Method 323, the “modifications” required for this method may be so significant that the current analytical procedures may not be acceptable and an entirely new procedure may need to be developed (i.e., the analytical procedure is not sensitive enough).

Proposed Method 323 for Measurement of Formaldehyde Emissions from Natural Gas-Fired Stationary Sources has several problems. Because Proposed Method 323 can only be used on gas-fired sources, it alone is not enough to support the proposal. EPA could not proposed use of this method on new oil-fired diffusion units that do not have CO control without test method validation data for these units.

Proposed Method 323 has a stated range of 270 to 10,000 ppb, and the lowest calibration standard required by Method 323 is at the sample gas equivalent concentration of 670 ppb, assuming the sample is collected at the maximum acceptable flow rate for a 1-hour test duration. Even using a four-hour test duration, the equivalent stack gas concentration would be approximately 170 ppb – well above the 43 ppb standard. This would result in all analyses being performed well below the lowest calibration value.

Proposed Method 323 cannot be modified to measure lower concentrations without significantly affecting accuracy and precision and calling into question the entire validity of the Method. This statement also applies to all of the other methods that EPA has referenced in the proposed rule. EPA cannot expect to simply “tweak” a few aspects of an existing Method and lower the detection limits by one or two orders of magnitude while still maintaining or improving the methods accuracy and precision. It is reasonable to expect that a significant method validation program would be required.

Even as written for the relatively high concentrations (i.e., 270 to 10,000 ppb), the accuracy and precision of Proposed Method 323 are poor. Significant, albeit “acceptable,” variability in results can be expected due to relatively loose test method performance specifications with respect to tester errors, contamination, and interferences in proposed Method 323, such as:

- a. Duplicate samples must agree within 20% (section 8.4.1),
- b. The field blank must be less than 50 % of the lowest calibration standard (i.e., field blanks must be below 0.5 µg per 2 ml aliquot – equivalent to 335 ppb in the gas being sampled) (section 11.2.2),
- c. The spike recoveries must be between 80 and 120% (section 8.4.2), and
- d. Daily calibration checks on the analytical instrument must be within 10 % on the calibration curve (section 10.3).

All of these requirements accept a significant amount of error in the field measurements. Furthermore, note that while the other methods referenced by EPA have different performance specifications, all of these methods accept significant margins of error, making it impossible to establish compliance with a “low” ppb-level standard.

It is also disturbing that when certain performance specifications in these methods are exceeded the data are not considered invalid; they are considered “suspect.” See, e.g., section 8.4.1. This requirement is vague. If performance specifications are not met, the data should be discarded for compliance determination purposes.

California Environmental Protection Agency, Air Resources Board Method 430 (CARB Method 430) is a test method widely used for the determination of formaldehyde and acetaldehyde in emissions from stationary sources. In the proposal EPA states that the data collected to support the MACT rule were collected using CARB 430 with a MDL of 2 to 3 ppb. We believe that EPA is severely overstating the practical source measurement capabilities of this method. Due to many potential sources of error and measurement variability, we do not believe that CARB 430 procedures can yield consistent/repeatable results for source concentrations below 40 to 50 ppb and question the accuracy of the method even at that level. Based on our measurement experience, we believe that, at 40 to 50 ppb, the precision of the method is only about 50%. With this method, in particular, there is a significant difference between the accuracy of the analytical technique (high performance liquid chromatography—HPLC) and the accuracy and precision of the field measurements. CARB’s stated precision estimates ranged from 3% to 65% -- “with most values ranging, from 10% to 40%.” CARB has obviously experienced numerous problems with field and blank contamination and has attempted to deal with these issues by developing ways to calculate the detection limit for each test series and by developing a fail-safe “reporting limit” (five times the field blank) value which is to be used when the field blank is too high or the source emissions are too low. Furthermore, the method of calculating the detection limit only addresses the apparent random error seen in the batch of blanks that is associated with the measurements and does not address non-random, systematic error in the method or batch measurements.

The reporting limit (five times the field blank) concept of CARB 430 is unacceptable, and we note that high ambient formaldehyde concentrations can significantly and may frequently affect test results. EPA stated that average ambient concentrations of formaldehyde range from 2 to 25 ppb. Furthermore, EPA states that the national urban average formaldehyde concentration is 4.2 ppb but that the differences between maximum and minimum hourly averages would be even greater than the 23 ppb difference observed in the annual averages. Previous Gas Research Institute (GRI) tests showed hourly ambient levels of formaldehyde up to 200 ppb. Based on this information, there is a significant concern with sample contamination, especially with any “wet chemistry” method.

These statements raise two fundamental issues. First, imagine a similar measurement situation of trying to recover Reference Method 6 samples in a room with 600 ppm sulfur

dioxide. The thought of doing so without contaminating the samples at least to some degree is laughable. Second, there can be significant variation in ambient formaldehyde concentrations. It is recommended that, as part of future methods development, EPA conduct ambient formaldehyde tests and develop ways to correct for ambient contributions/contamination in the results.

In addition, we should note that the stated detection limit (with an uncertainty of <1%) established by SW846, which is also a DNPH method similar to CARB 430, is 90 ppb.

Test Method 320 in Appendix A of 40 C.F.R. Part 63 is another suggested formaldehyde test method that uses extractive Fourier Transform infrared (FTIR) spectroscopy technique. As with the other methods, Method 320 has some relatively lenient performance specifications. In particular, the spike recovery requirements are 70% to 130%. For compliance testing purposes, measurement errors of up to 30% can be significant.

Regarding possible revisions to Method 320, EPA speculates that testers will begin using an FTIR path length of 100 to 125 meters. EPA does not state how many of these instruments are being used by source testing companies. We are only aware of two FTIRs equipped with cells that have this long of a path length and are not aware of any that have been tested and validated in the field for compliance testing purposes. What affect does the extended path length have on instrument precision, accuracy, signal strength, potential interference, etc? We believe that the FTIRs currently being used, at least to some degree, in the field have formaldehyde detection limits of approximately 50 to 60 ppb. The current MDL for Method 320 is in low ppms not ppbs. EPA has not provided any data to support their speculation concerning the future of FTIR development. Even with these currently available instruments, there are very few qualified operators available to conduct compliance tests.

EPA states that with the longer FTIR path lengths these instruments should provide detection limits below 43 ppb. What does this mean? The detection limit must be significantly lower than the standard – preferably a factor of 10 or more. EPA needs to provide additional details regarding the actual detection limits and associated field application precision and accuracy before further recommendations can be made.

RMB reviewed test results from a recent EPRI report where CARB 430 and Method 320 (FTIR) were compared. There was very poor agreement between the two methods. The results of these comparative tests using CARB 430 and FTIR procedures indicated that the CARB measurements were always substantially lower than the FTIR measurements. For example, the CARB 430 results were reported as non-detectable concentrations of <11 to <12 ppb while the FTIR results indicated “uncorrected” concentrations ranging from 34 to 125 ppb (a factor of 3 to 10 times higher). Once corrected for “sampling system off gas interferences,” the FTIR results ranged from 0 to 61 ppb. We consider this magnitude of disagreement and variability impossible to accept when considering compliance measurements with a 43 ppb standard. Clearly one, and probably both test methods are yielding incorrect results.

Conclusions on the CT Mact

Clearly, EPA has considerable work to do on the proposed CT MACT rule. They have proposed both instrumental and wet chemistry compliance measurement methods techniques that are likely to be impossible. It seems to us that considerable additional background data needs to be collected to fully understand the instrumental measurement issues. Obviously, considerable test method development work is also needed. This work needs to be completed and peer reviewed prior to promulgation of the CT MACT regulation.

The Proposed IB MACT Rule

We are not going to spend much time on the IB MACT rule because it does not have much effect on the utility industry. Our primary interest is the construct of the rule and how this construct may influence the pending utility boiler MACT rule.

The IB MACT rule regulates emissions of particulate matter (or selected metals), CO, HCL and HG from new solid- and liquid-fired boilers and existing solid fuel fired boilers. It is a complex rule because of the number of source categories and the various emission limits. It also has an interesting construct in a number of areas that sets new, and troublesome precedent.

No Recognition of Compliance Margin Issues

For example, this proposed rule contains not only emission limits but associated work practice or operational restrictions with respect to fuel and emission control system operation that greatly limit boiler operational flexibility. In essence, the rule does not recognize compliance margin during the initial performance test and, even if the source is emitting at a level 10% of the emission limit, the rule restricts future operation of the control device(s) to those conditions (or better) that exist at the time of the test. The operational parameter limitation approaches proposed by EPA are simplistic and ignore many of the true operating characteristics of control equipment. At a minimum, EPA's proposal would have the perverse effect of requiring sources to reduce the performance of their control devices for the performance test period. Although the negative impact of this approach on industrial boilers would be significant by itself, we are also very concerned how the precedents being set by this proposed rule might impact the pending proposal of the Utility Boiler MACT rule.

The general requirement that EPA can dictate a specific set of operating parameters for the control equipment and then require that a source operate there, or better, in the future is an onerous requirement that has a number of practical and technical problems.

As a general rule sources buy new control equipment with an "operational" margin of compliance so that there is flexibility to account for control equipment problems or other operational issues. There will be problems because control equipment is just made up of mechanical and electrical hardware and failures will occur. Therefore, most new

electrostatic precipitators (ESPs) are bought with extra fields and sections where the source can operate in compliance with the applicable emission regulations even when there are problems with parts of the control equipment. Likewise, new fabric filters (FF) or baghouses and scrubbers are often bought with extra capacity (additional modules) in the control equipment.

The control device operating parameter procedures in EPA's proposal call for setting the maximum and/or minimum (as appropriate) parameter value based on the conditions that exist during the performance test. If the performance test is just barely in compliance with any emission limit, and the assumption is that the emissions are directly related to the control device operating parameters, this approach might be acceptable.

Unfortunately, this assumption is incorrect.

However, many performance tests are performed at a level of control that not only includes a significant margin of compliance, but that also may not be directly correlated to control device operating parameters. Unfortunately, control device parameters, especially with scrubbers and ESPs, are interrelated with the design of the device and the interaction between the various parameters. For example, total ESP power may be completely unrelated to ESP performance for a multi-section ESP. ESP power is, therefore, not an appropriate indicator for ESP performance except for the most simple, single chamber ESP.

Control device operating parameters may vary widely with little effect on the emission rate of the pollutant being controlled. In addition, normal operation of emission control devices contains considerable variability. For example, on a scrubber the pressure drop and liquid flow rate are usually a function of boiler load. As a result, recording of control device parameters at levels above or below those recorded during a performance test might be consistent with good operation of the control device and compliance with the standard. EPA's failure to consider this normal operational variability in the proposed rule could make the proposed standard much more stringent than the proposed numerical limit and could interfere with operation of the control device.

The only way to set control equipment parameters at the level recorded during performance testing and still maintain the equipment control margin is to perform a CAM type exercise with multiple tests and the control equipment performance degraded. This testing procedure should be specifically allowed and any emission excesses during the testing should be specifically excused in the rule.

RMB has conducted a number of CAM tests on particulate control devices and, thus, has considerable experience in this area. In many cases, we find that the State Agency or EPA regional office is very nervous about allowing the performance of the control equipment to be degraded, only for the purpose of CAM testing, to approach the level of the standard. In fact, we have been told by some state regulators that such action would not be allowed. The proposed Industrial Boiler MACT rule states that, "You must conduct performance tests at the representative process operating conditions that are expected to result in the highest emissions of hydrogen chloride, particulate matter, and

mercury, and you must demonstrate initial compliance and establish your operating limits based on this test. This requirement could result in the need to conduct more than one performance test." While this rule language implies that the control equipment can be detuned for the performance tests, it should be explicitly stated.

In addition, the parameter testing/setting procedure contemplated by EPA in this proposed rule cannot be accomplished unless the source is shielded from excess emissions during the performance tests. Control device performance can be variable based on a number of different operating parameters and is certainly not precisely predictable in advance. Therefore, it is possible that the control device will inadvertently be detuned to the point that emissions over the limit will be measured. Under such circumstances, the excess emissions should be explicitly excused by the rule. If excess emissions are not permitted during the performance/parameter setting test period, EPA will be removing compliance margin from the control device and penalizing the source.

The proposed IB MACT rule contains fuel based operating limit procedures for chloride, metals and mercury that are flawed in that they are related to the performance test period and the emissions achieved during that performance test, no matter the margin of compliance. These procedures should be related to the actual emission limit.

The operating limit procedure proposed by EPA seems to assume that a source will fire a fuel that has the maximum chloride, metals and mercury content during the performance test and, thus, this fuel will become the cap. There is no connection to the emission limit and, therefore, the procedure is fundamentally flawed and unfair. For example, if a source were to conduct the performance test showing chloride emissions of only 10% of the emission limit, the chloride content of the fuel used during the performance test would become the cap for future fuels or until a new performance test was performed. Why should this source be capped at such a low fuel chloride content when it has a 90% compliance margin?

This operating limit approach has no technical merit and exerts a level of over control that is unreasonable. These operating limit procedures should be modified so that they relate the fuel constituents and applicable emissions on the day of the performance test proportional to the emission limit. This would provide factors that could be used to evaluate new fuels. Of course, a small safety factor (say 10%) could be incorporated into each factor.

In addition, the proposed rule requires chloride and mercury analysis on each "new fuel" and this has the potential to disrupt and add considerable cost to long-standing fuel purchasing practices. The definition of a "new fuel" is vague in that it only references a new supplier. In some cases this definition would work if a supplier is only providing fuel from one mine and even one seam in a mine. Unfortunately, many suppliers provide fuel from a variety of sources, perhaps from a multitude of mines or refiners. In addition, sources are likely to use a variety of fuel suppliers based on fuel procurement bids.

Record Keeping and Reporting Issues

The recordkeeping and reporting requirements of the proposed industrial boiler MACT rule are burdensome, costly and require unnecessary data. There is no standard data format or the opportunity for electronic reporting mentioned. Much of the data required will have to be hand gathered and hand entered into an electronic data base(s). We assume it will then have to be printed and sent to the permitting authority. Who will be responsible for reading all of that material and then responding to the source? What will be done with all of this information and paper?

The magnitude of the data management and handling process that would have to be developed at a reasonably sized industrial facility, that has four or five solid-fuel boilers, receiving spot market fuel is staggering. Someone will have to track fuel consumption, operating hours, startups, shutdowns including dates and times, equipment malfunctions including dates and times, numerous operating parameters including dates and times of deviations, CEMS calibration data, CEMS maintenance, CEMS out of control periods including reasons, dates and times, performance test reports, fuel sampling reports, vendor reports and a number of other pieces of information. Obviously, much of these data cannot be gathered in an automated, electronic manner and will have to be collected manually. Once the data are gathered, decisions will have to be made regarding what has to be reported and someone will have to generate the report. This would be a massive job, and the probability of making an error during the process will be virtually 100%. Not withstanding the effort required and the cost to prepare the report, what responsible official could sign such a report with absolute confidence that it contained no errors?

It is highly probable that a source would decide to automate as much of the reporting and record keeping as possible. This decision would be driven by the desire to reduce the amount of manual data handling and to improve the reliability of the data. The equipment cost alone for implementing an automated (to the extent possible) data collection and report generation system is likely to be very high. There also appears to be little opportunity for standardization of the software because there is no standard reporting format, so significant costs will be incurred for custom software.

Conclusions on the Proposed IB MACT Rule

We have only discussed a few of the troubling aspects of the proposed IB MACT rule. The most serious problem is that the rule does not recognize compliance margin and locks the source into the control device and fuel conditions that existed at the time of the last compliance/performance test. This regulatory approach is onerous, unreasonable and dramatically reduces the operating flexibility of the source. The only word that can be used to describe the record keeping and reporting requirements is insane. There is no standard reporting format and much of the data required will need to be gathered manually. We anticipate a reporting disaster.

Overall Conclusions

The CT and IB MACT rules are just not well done. It is clear that EPA, or its consultant, just did not put much thought into development of the rules. Hopefully, EPA will read and carefully consider the voluminous comments it received. It is possible that workable rules will result, but my confidence level is low.