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GENERAL

Q1. If I have boilers that have been abandoned in place for a few years now, are they subject to the rule? Do I need to submit initial notification for those boilers?

A. If the boilers are not decommissioned, you should submit initial notifications for each boiler. They would be subject to the rule upon startup (or the compliance date of the rule, whichever is later).

Q2. Can any of the new 63.7522 averaging provisions be applied to dual fuels used by one boiler (e.g., averaging our emissions when firing gas with those when firing oil)?

A. As stated in 63.7522, emission averaging is only allowed between units in the same subcategory. However, you appear to be asking if you can average the emissions from when a dual fuel unit is burning oil with the emissions when that same dual unit is burning gas. In this situation, 63.7520(c) would apply and compliance would be based on the emissions when firing oil.

Q3. With respect to 40 CFR 63.7510(c), is there a typo in the second sentence of the paragraph? The rule says, "Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 12 or 11 through 13 to this subpart, as specified in Sec. 63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in ...." Should "12" refer to Tables "1, 2" or 11 through 13?

A. You are correct. It is a typo. Thanks for the catch.

Q4. It is my understanding that a facility that is currently a major source of HAPs, can become an area source before the first substantive date of the Major Source Boiler MACT (i.e., 2016), and comply with the Area Source Boiler MACT/GACT (NESHAP JJJJJJ) provisions. This is based on EPA's memorandum that was published in 1995 (attached), and specifically noted the first substantive compliance date of a MACT rule as the last day to switch to an area source, before Once In, Always In takes effect. There has been many changes to the MACT program since then, but I believe this memorandum still represents EPA's policy, esp. when it comes to the boiler rules. Could you please confirm?

A. The "Once In Always In" Policy does represent the Agency's policy. You are correct that a source must reduce their emissions below major source thresholds prior to the compliance date of the rule.

Q5. If a major facility wants to be an area source, what is the latest date to opt out, and what has to happen by then? (I.e. do they need a federally enforceable permit restriction, limiting HAPs to less than the major source thresholds [10/25 TPY]?).

A. A facility would need to become an area source before the first applicable compliance date, which would be January 31, 2016 for existing sources. The facility would need to show that their potential to emit HAP is less than 10/25 TPY, and a federally enforceable permit restriction would be one way to show emissions are below major source levels.

Q6. If we notify now that facility is a major, can we still opt out later and become an area source?

A. Yes, an existing facility has until January 31, 2016 to become an area source. However, the first applicable compliance date for new sources is the date of startup.

Q7. Our gas fired boiler was installed in 2011: When do we need to complete the tune-up and energy assessment? The rule language seems to indicate that we need to have completed the energy assessment by January 31, 2013 as this would be a "new" boiler (installed after June 2010). Surely this can't be correct?

A. The amendments to the major source boiler rule (subpart DDDDD), published on January 31, 2013, reset the compliance dates for the tune-up and energy assessment. However, new units are not subject to the requirement to conduct an energy assessment, as indicated in item 4 of Table 3 in the January 31, 2013 amended rule or item 3 of Table 3 in the March 21, 2011 final rule

As for the initial tune-up requirement for new units, the January 31, 2013 amendments revise the date for the initial tune-up for new units. Section 63.7510 was revised and paragraph 63.7510(g) states:

> (g) For new or reconstructed affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in § 63.7540(a) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7540(a).

This means a "new" gas-fired unit would need to conduct the initial tune-up by either January 31, 2014 (if required to conduct tune-up annually), January 31, 2015 (if required to conduct tune-up biennially), or January 31, 2018 (if required to conduct tune-up every 5 years).

Q8. I have a question about the 48-hour limitation on alternative fuels for "units designed to burn gas 1". Section 63.7575 defines the unit designed to burn gas 1 to include the periods for maintenance or gas curtailment where alternative fuels, such as fuel oil, may be burned.

Can this be interpreted to mean 48 hours *of fuel use capacity*? May the unit burn up to an equivalent capacity (i.e., heat input) if 48 hours of fuel were combusted at maximum capacity? This allows for more than 48 hours of actual boiler operation on alternate fuel, if the unit is operated at less than 100% capacity. The unit would still use an equivalent amount of fuel, generating similar emissions if it were fired at 100% capacity during those 48 hours and this type of interpretation would allow for more flexibility for the facility during instances of gas curtailment, etc. I understand the goal is to keep the unit on 'gas 1' as much as possible but circumstances out of the facility's control may dictate otherwise.

> A. No, the 48 hours of testing allowed under the definition of "units designed to burn gas 1 subcategory" in 63.7575 refers to operating hours not fuel capacity or amount of fuel burned. Therefore, a unit that burns liquid fuel for more than 48 hours during any calendar year, not including periods of gas curtailment, would be in the "units designed to burn liquid subcategory."

Q9. USEPA relied on information from the Department of Energy with respect to the expectations for the scope and content of an energy assessment. I would appreciate if you could provide the link to the DOE website to which you referred during our conversation that gives guidance on conducting energy assessments.

> A. Here is the link to the DOE website on energy assessment.
> http://www1.eere.energy.gov/manufacturing/tech_deployment/energy_assessment.html

Q10. DUAL FUEL BOILERS
A major source facility has a couple of large (>10MMBtu/hr) dual fuel boilers (with natural gas as the primary fuel) in a steam plant. They are in the process of decentralizing the plant which will result in decommissioning these boilers. However, the boilers have a large reserve of oil that they will need to burn prior to being able to shut down and decommissioning these boilers. In order to get rid of the fuel oil, they will need to operate the boilers on the liquid fuel for at least a week, certainly more than 48 hours. The questions that arrive are the following:
Qa. Can they burn all the fuel as planned, since they will be done burning the liquid fuel before the compliance date of the rule? Would they need to report these boilers as liquid fired in the initial notification due May 31, 2013?

> Aa. The unit must have an initial notification if it is in operation at the time of the deadline for notification. The notification should report the subcategory of the boiler based on the definition that the boiler meets at the time of notification (if they could not meet the definition of gas, then liquid fuel).

Qb. If they burn the fuel prior to the due date of the initial notification (May 31, 2013), but the boilers have not been decommissioned yet, do they need to submit an initial notification, and if so, can they claim the boilers are Gas 1 subcategory (since they will not be burning liquid fuel for more than 48 hours anymore). When do I start counting the calendar year for determining the subcategory of the boiler that will go in the initial notification?2012, or what is expect for 2013, 2014, 2015 or 2016?

Ab. If the unit is not decommissioned, an initial notification should be submitted based on the subcategory that would apply to the unit at the time of the notification (if they could not meet the definition of gas, then liquid fuel). However, because it is an existing unit, it would not need to demonstrate compliance until the compliance date of the rule. If the unit is decommissioned prior to the compliance date, it would no longer be subject to the rule requirements. Generally, calendar year begins on January 1 and ends on December 31 for a given year.

Qc. What if they are able to decommission the boilers prior to May 31, 2013, would they need to submit an initial notification anyways? And under which subcategory?

Ac. If the unit is decommissioned prior to the notification date, and is not intended to be restarted, it does not require an initial notification.

Qd. What is considered a non-operational boiler that would not be subject to the rule? These boilers will be left in place, but they will never be used again. So, they would not have any requirements under the rule, correct? To be considered a non-operational or decommissioned boiler, what are the requirements? Is it enough to disconnect the piping? Does the burner need to be removed? Are there specific things that need to be done to the boiler so that is considered a decommissioned boiler that will not operate ever again?

Ad. EPA does not have specific requirements that constitute decommissioning, other than that the boiler be rendered inoperable. However, the facility should contact the state in which they are located to ensure they comply with any state requirements. Also, if the unit will not operate again, the facility should make sure the unit is removed from the state list of emission sources and any permits are closed out properly.

APPLICABILITY

Q11. The major source rule exempts hot water heaters with a capacity of 120 gal or less, and it also exempts hot water boilers with a heat input capacity of 1.6 MMBtu/hr. So any small boiler (<1.6MMBtu/hr) that is used to heat water is exempted from the rule?

A. The definition of hot water heater in 63.7575 includes any water heater (not generating steam) that is no more than 120 U.S. gallons in capacity or has a heat input capacity of less than 1.6 MMBtu/hr. Those two thresholds are independent of each other, although both may apply in some cases.

Q12. Question concerning if a boiler is a new source or an existing source. The boiler in question was constructed prior to 6/4/2010. However, the company that constructed and operated the boiler went out of business and the boiler was not in use for several years. A new company has purchased the facility and started operating the boiler in June of 2012. Would the boiler be considered a new source or an existing source?

A. If they haven't done anything that would trigger reconstruction, then it would be based on the original date of construction (which in this case would make them an existing unit).

Q13. You state that "a boiler that burns oil for more than 48 hours during a calendar year would be in the 'unit designed to burn liquid fuel' subcategory". Is that also true for a boiler that burns oil for LESS than 48 hours during a calendar year, if any of that operation isn't strictly for "periodic testing" as described in the definition of the "gas 1" term?

A. If a unit burns oil for less than 48 hours in a calendar year, outside of periods of gas curtailment, it would meet the definition of a "Unit designed to burn gas 1 subcategory."

Q14. Section 63.7575 defines the unit designed to burn gas 1 to include the periods for maintenance or gas curtailment where alternative fuels, such as fuel oil, may be burned. Can this be interpreted to mean 48 hours *of fuel use capacity*? May the unit burn up to an equivalent capacity (i.e., heat input) if 48 hours of fuel were combusted at maximum capacity? This allows for more than 48 hours of actual boiler operation on alternate fuel, if the unit is operated at less than 100% capacity. The unit would still use an equivalent amount of fuel, generating similar emissions if it were fired at 100% capacity during those 48 hours and this type of interpretation would allow for more flexibility for the facility during instances of gas curtailment, etc. I understand the goal is to keep the unit on 'gas 1' as much as possible but circumstances out of the facility's control may dictate otherwise.

For example, if a "unit designed to burn gas 1" operates at 50% capacity while burning oil during a period of gas curtailment, it could then theoretically operate 96 hours and still burn the the same total gallons (Btu input) while generating similar emissions.

A. No, the 48 hours of testing allowed under the definition of "units designed to burn gas 1 subcategory" in 63.7575 refers to operating hours not fuel capacity or amount of fuel burned. Therefore, a unit that burns liquid fuel for more than 48 hours during any calendar year would be in the "units designed to burn liquid subcategory".

Q15. I just want to verify whether the regulation concerning the Docket ID listed above (EPA-HQ-OAR-2002-0058) applies as I think it does to offshore oil and gas operations. From my initial reading of the rule, I believed that it does, but I would like to make absolutely sure.

A. It is possible that the Major Source Boiler Rule (40 CFR 63 Subpart DDDDD) could apply to a boiler located at an offshore oil and gas facility; if the boiler at the facility met the definition of an affected source in the rule (see section 63.7485).

Q16. The process heater definition states it is "an enclosed device using controlled flame." Does this mean all parts of the device are enclosed (the flame side and the other process material) or just the flame part? We have a situation where natural gas is being combusted and sent through burner tubes and the other side is an open tank of water.

A. The process heater definition phrase "an enclosed device using controlled flame" means just the flame part that is the fuel combustion chamber. However, the situation you are describing would appear to meet the definition of a "boiler" which states "in which water is heated" in both the Boiler MACT (subpart DDDDD) and the Boiler Area Source Rule (subpart JJJJJJ). If this facility is an area source, the definition of "process heater" does define some water heaters which are not considered boilers and are therefore not subject to subpart JJJJJJ.

Q17. The facility is a university and has several small boilers that provide heat to residential dorms. According to 40 CFR 63.7575, a "residential boiler" means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system.
This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:
1. A dwelling containing four or fewer families; or
2. A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Based on the first portion, it appears the exemption was meant to cover dorms (refers to universities). However, these dorms would not necessarily have 4 or fewer families and I'm not sure if subdivision into condominiums or apartments is intended to cover subdivision into dorm rooms. Could you help confirm whether a dorm is included in this exemption?

A. In the Boiler MACT (subparts DDDDD), the intent was to cover boilers located in dormitories located on campuses. The inclusion of the "residential boilers" to the list of boilers not subject to the boiler rules was not to subject boilers in single family homes located at industrial, commercial (e.g., farms), or institutional (e.g., universities, military bases) facilities. Our intent was not to cover, say, the boiler in the Dean's residence which could be considered to be an institutional boiler, and not a residential boiler, because the residence is owned by the University and not the Dean. So, a boiler located in a dormitory that does not meet the definition of “residential boiler” would be subject to the Boiler MACT.

Q18. We are making solid waste determinations under the NHSM rule in which we are comparing various materials to “traditional” fuels as part of the legitimacy criteria. In the case where a material IS comparable to a traditional fuel – say, coal, - the material is deemed to be NOT a solid waste. The combustion unit that is used to burn the material is then subject to GACT/MACT. My question is, what should the material be classified as under those rules? Should it be coal (or whatever traditional fuel I compared it with under the NHSM test)?

A. Under the boilers rules, secondary material would be classified based on whatever listed fuel definition applies. That is, if it meets the definition of “biomass or bio-based solid fuel” under the boiler rules it would be considered “biomass” even if its non-solid waste determination was based on it being comparable to coal.

The boiler rules only require the source to document that no secondary materials that are solid waste are combusted and, if they burn non-solid waste secondary material, to document why the material was determined not to be a solid waste.

Q19. In the original Boiler MACT waste heat boilers that had a burner that supplied over 50% of heat to it was considered a boiler. In the updated version, the definition of a waste heat boiler was changed. Are there any waste heat boilers/heat recovery units or duct burners subject to the Boiler MACT?

A. The Boiler MACT covers boilers as defined in the rule. The amended definition of “Boiler” states waste heat boilers are excluded from this definition. The definition of “Waste heat boiler” was also amended. So, a waste heat boiler, as defined, with or without duct burners is not subject to the Boiler MACT.

Q20. Is coke oven gas considered "clean" gas for purposes of boiler MACT?

A. Coke oven gas is not a listed "clean" gas but can qualify if it meets the Hg level criteria. Also, process gases that are regulated under another subpart of Part 63 are exempt from our definition of "gaseous fuel" and not subject to the Boiler MACT.

Q21. Does the regulation define and exclude hot water heaters?

A. Yes. A hot water heater with a capacity of 120 gallons or less or a hot water boiler (e.g. not generating steam) with heat input capacity of less than 1.6 MMBtu/hr burning oil, biomass, or gas, is not covered under the rule under the definition of hot water heater.

Q22. Is a boiler used for comfort heat located at an industrial facility covered under the rule if it meets the definition of a "hot water heater"?

A. No. As noted above, a hot water boiler (not generating steam) a heat input capacity of less than 1.6 MMBtu/hr burning oil, biomass, or gas, is not covered under the rule under the definition of hot water heater.

Q23. A gas-fired boiler is allowed to burn oil during periods of gas curtailment and still be considered gas-fired and not covered under the rule. If a source has a contract with a gas supplier, and the under the terms of the contract the gas supply is curtailed, does this qualify as a period of natural gas curtailment?

A. Yes. A period of natural gas curtailment or supply interruption means a period of time during which the supply of natural gas is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement does not constitute a reason that is under the control of the facility. However, an increase in the cost of fuel does not qualify as a period of natural gas curtailment. Onsite gaseous fuel system emergencies or equipment failures may qualify as periods of supply interruption if the emergency or failure is beyond the control of the facility.

Q24. Is there a limit on the number of hours a gas-fired boiler may burn oil during periods of natural gas curtailment or supply emergencies and still be gas-fired and not covered by the rule?

A. No.

Q25. What is the difference between solid waste and fuel?

A. EPA finalized a rule codified in 40 CFR Part 241, subpart B which identifies whether a non-hazardous secondary material (NHSM) is, or is not, a solid waste when burned in combustion units. Boilers which burn NHSM that is a solid waste would be regulated under incinerator regulations developed under Section 129 of the CAA. Boilers which burn NHSM that is not a solid waste would be regulated under boiler regulations developed under Section 112 of the CAA.

Q26. If a university, boarding school, or other institution owns residential buildings which are used to house students or staff, are the boilers serving those buildings considered institutional?

A. Yes. However, residential boilers used to provide heat or hot water in any dwelling with four or fewer family units are not covered by the rule. This includes residential boilers used in a dwelling with four or fewer family units at a university, but not a boiler in a large dormitory at a university.

COMPLIANCE TESTING

Q27. If we are in the "Unit designed to burn liquid" category, with regard to the initial performance test, we are aware of what 63.7520(c) says, but are unclear as to how EPA is interpreting it for the source type that I described (natural gas-fired boiler using oil for cold startup and flame stabilization only). Specifically, there are conflicting requirements to test using the "type of fuel or mixture of fuels that has the highest content of chlorine and mercury" (which in our case would be the oil or oil/gas mixture, since it would have higher content of Cl and Hg than the gas alone), yet also test at high load (where we don't use oil), because Table 4 shows that we would be restricted to a load that is no more than 110% of the load that we test at during the performance test. In addition, oil is not used for a long enough duration to satisfy the minimum applicable sampling times/volumes as required by 63.7520(d).

A. For the described unit (a natural gas-fired boiler using oil for cold startup and flame stabilization only), the initial performance test would be conducted at high load firing natural gas. This is based on section 63.7510(a)(2)(i) which states "For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected sources units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under §63.7521 and Table 6 to this subpart." Therefore, if the oil is only burned for startup and flame stabilization purposes, the unit would be considered to burn a single fuel (i.e., natural gas) and under 63.7520(c) the initial performance test would be conducted on natural gas.

Q28. §63.7520(e) requires us to determine compliance using F-factors. If we test when co-firing oil and gas, do the emissions limits apply to the overall lb/MMBtu for the two fuels, or just the lb/MMBtu for oil (and if the latter, how are we supposed to separate that out)?

A. The emissions limits apply to the overall heat input (lb/MMBtu) for the two fuels.

Q29. The situation we are evaluating is a gas-fired boiler that uses a supplemental fuel (oil) only for startup, unit shutdown, and transient flame stability purposes, as well as in situations involving gas curtailment. Because the need for oil for transient flame stability is likely to exceed 48 hr/yr it seems like we are stuck in the "Unit designed to burn liquid" category, but how would we conduct our performance test (to demonstrate compliance with the "unit designed to burn liquid" limits) at high load (burning gas only).

A. If the unit is in the "unit designed to burn liquid" subcategory, then it should demonstrate compliance with the limits associated with that subcategory. This is independent of what fuel is being burned during the compliance demonstration. So, if the representative conditions for the stack test would be running all or mostly natural gas, that is how the test should be conducted. The rule states in 63.7520(a) "You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the <u>representative performance</u> of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests."

There is no requirement for the unit to test during times of burning oil, unless that would be considered representative performance of the unit. During startup and shutdown the emission limits do not apply, the unit is subject to work practice standards during those times, so the emissions during startup and shutdown should not be considered for purposes of performance testing.

Q30. In Section 63.7510(a), which refers to initial compliance requirements and how "affected sources that burn a single type of fuel" are exempt from certain fuel analysis requirements, there is a sentence which states that "For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected sources that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements…." The sentence refers to the "subpart" (and not just that "section"). So does this mean that if we have a unit that burns gas but requires oil for startup, unit shutdown, and flame stability purposes, we can still consider it to be a "Unit designed to burn gas 1" (even though the definition of that term in 63.7575 does not identify an exemption for fuels used for startup, unit shutdown, and flame stability purposes)? Or would the use of oil for startup, unit shutdown, and flame stability purposes kick us in to the "Unit designed to burn gas 2" category (because the "Unit designed to burn gas 1" definition only mentions an exemption for liquid fuels burned during periodic testing and gas curtailment)?
A follow-up question: if a natural gas-fueled boiler <u>is</u> kicked into the "Unit designed to burn gas 2" category as a result of burning oil for startup, unit shutdown, and/or flame stability purposes, how do we address compliance testing? I.e., usually testing is done during steady-state high-load conditions, in which case we would only be firing natural gas; if we try to test when burning oil, the test will be non-steady-state and/or too short to be able to obtain a large enough sample to detect some of the target pollutants at the levels identified in the rule?

A. The requirement to conduct a fuel analysis under section 63.7510(a)(2) is independent of the subcategory that a unit belongs to. A boiler that burns oil for more than 48 hours during a calendar year would be in the "unit designed to burn liquid fuel" subcategory. However, when that unit is completing their initial compliance requirements, they would review section 63.7510 and they would likely not need to do a fuel analysis because they would either fall under burning a single type of fuel (as described under 63.7510(a)(2)(i)) or burning natural gas co-fired with other fuels (as described under 63.7510(a)(2)(ii)).

For the initial performance test, section 63.7520(c) specifies that "You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart."

Q31. Per 40 CFR 63.7510(a)(2)(i), a boiler that burns a single type of fuel is not required to conduct a fuel analysis for each type of fuel burned in the boiler. Supplemental fuel used only for startup is not subject to fuel analysis. I am currently working on the Title V renewal for a facility that operates a boiler which is permitted to burn coal & wood. This boiler is subject to Boiler MACT. Other than for the initial testing period which was completed by December 2006, the boiler has only burned wood. Note that natural gas is used for startups only. Will this boiler qualify for the exemption from the fuel analysis requirement as specified in Sec. 63.7510(a)(2)(i)?

A. Yes, if a single type of fuel is combusted in the boiler, regardless of what the unit is permitted to burn. However, if the boiler starts burning coal, this would trigger the requirement to do a fuel analysis?

Q32. What are the required steps that need to be taken to propose equivalent methodology for coal mercury sampling to satisfy the requirements of the ICI Boiler MACT rule (a portion of Table 6 is copied below)? We have an Ohio Lumex analyzer RA915+ analyzer, which utilizes direct thermal desorption with atomic absorption, but no gold amalgamation.

A. As stated in Table 6 of the Boiler MACT, an equivalent method can be used without prior approval. "Equivalent" analytical procedure is defined in 63.7575 as:

> (6) An equivalent pollutant (mercury, HCl) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

Otherwise, to use an alternative analytical method, as stated in 63.7521(b)(1), you must submit the fuel analysis plan to EPA for review and approval. Alternative test method request should go to Dr. Conniesue Oldham, here in RTP. The address is:

Dr. Conniesue Oldham, Leader
Measurement Technology Group
Air Quality Assessment Division
Mail Code E143-02
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

Q33. This question is concerning a new boiler subject to the Boiler MACT (Rule) requirements for a major source that will co-fire multiple fuel types. The questions contained herein are related to a proposed new boiler that would be subject to the Rule. The specific boiler would burn up to 100% firing on natural gas, refinery gas or a blend of these two (2) Gas 1 type fuels. Additionally the boiler would alternately burn up to 50% of its Btu input from liquid fuels and the remaining Btu heat input from natural gas and/or refinery gas.

Our specific question is a clarification for the determination of compliance with the HCl, mercury and TSM emission limits while co-firing the liquid fuels with natural gas and/or refinery gas through the use of fuels analysis using Rule Equations 16, 17 and 18. While §63.7510(a)(2)(ii) does not require fuel analyses for this type of boiler, the source would be subject to an HCl and Mercury emission limit in Table 1 when burning liquid fuels. In this case, fuel analyses could be used to demonstrate compliance. In accordance with the Rule, it would not be necessary to analyze either the natural gas or the refinery gas for chlorine, mercury or metals (for TSM). It is not clear from the Rule requirements when using fuels analysis and Equations 16, 17 & 18, how the Btu value for the fuel gases would be taken into account for determining compliance with the HCl, mercury and TSM emission standards.

It is my understanding from our conversation, that a reasonable interpretation of the intent of the Rule would allow the Btu value of the natural gas and/or refinery gas to be summed (proportional to the amount of fuel fired) in Equations 16, 17 and 18 with the Btu values for the liquid fuels, while assuming no chlorine, mercury or metals content of the natural gas or refinery gas in order to determine compliance with these emission standards while operating as a liquid fuels boiler.

A. The interpretation presented above on determining compliance for a boiler co-firing natural gas, refinery gas and liquid fuel is correct. §63.7510(a)(2)(ii) specifically states "When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis on those fuels …" Furthermore, §63.7510(b) states that for boiler that demonstrate compliance through fuel analysis, "The fuels described in paragraph (a)(2)(ii) are exempt from these fuel analysis." The intent of equations 16, 17, and 18 in §63.7530(c)(2) is to deal with fuel mixtures, the worst case mixture for the pollutant of concern. Thus, the total Btu value of the mixture (natural gas/refinery gas and liquid fuel) would be used in the equations.

Q34. For PM is an annual performance test enough? We have no PM air pollution control device. Is there any other PM monitoring required?

A. If no control device is use to demonstrate compliance with the PM limit, you must monitor operating load (see item 8 of Table 4 and item10 of Table 8) based on the operating limit set during the most recent PM performance test.

Q35. If we decide to comply with TSM instead of PM limit can we do fuel analysis to demonstrate continuous compliance?

A. Yes, as indicated section 63.7510(b).

Q36. I'm trying to figure out the compliance requirements for a boiler that burns biomass and some natural gas. Can we call it a single fuel boiler since there are no fuel sampling requirements for natural gas?

A. Yes, §63.7510(a)(2)(ii) states "When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those fuels according to §63.7521 and Table 6 to this subpart."

IMPLEMENTATION: TUNE-UPS

Q37. In our current tune up activities, due to a common stack, we have encountered confined space issues which will likely prevent us from being able to conduct the internal inspection of the burners until we are able to take both boilers off-line later this spring. The boilers at major sources are used for building heating and to provide steam for main EGU start up but do not provide steam for electrical generation. § 63.7540 allows burner inspections to be delayed until planned entries for storage vessels and process equipment. I do not see a definition for process equipment in subpart DDDDD. Does the term process equipment include auxiliary boilers?

A. You can delay the burner inspection until both boilers are shutdown, assuming it is a confined space situation (which was the reason for the allowable delay specified in 63.7540). Based on what is described, waiting until both boilers are shutdown would meet the requirement in 63.7540. However, you would still need to meet the tune-up schedule required for each boiler (every 1, 2, or 5 years depending on the subcategory), so you could only delay the inspection if the delayed date would still meet the required schedule.

Q38. When must a new unit do its initial tune-up?

A. New boilers which commence construction after June 4, 2010 are not required to conduct an initial tune-up at startup, but are required to conduct the required biennial tune-up within 25 months of startup of the boiler.

MONITORING

Q39. What happens if an existing oil-fired boiler already has a CO CEMS for another requirement? Would they petition for alternate monitoring and 30-day averaging period if they are concerned about credible evidence?

A. Because there is no alternative CO CEMS-based CO emission limit for existing liquid fuel-fired subcategories, the rule specifies that they comply with a stack test and demonstrate continuous compliance by maintaining the oxygen limit operating limit. To comply based on CO CEMS data they would need to petition for an alternative monitoring decision.

Q40. Table 8 to Subpart DDDDD "Demonstrating Continuing Compliance" specifies requirements for continuous compliance demonstration with the operating limits. Items 2, 4, 5, 6, 7, 9 & 11 require the facility to calculate 30-day rolling average for operating parameters. Per item 10, boiler operating load – "You must demonstrate compliance by maintaining the operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test according to § 63.7520(c)." Am I correct that the facility is required to maintain hourly average operating load less than 110%? If so, Sec. 63.7525(d)(4) does not apply to load or steam generation monitor.

A. Our intent is that continuous compliance with the operating limit "operating load" is based on maintaining the 30-day rolling average as according to §63.7520(c). Our intent is more clearly stated in item 9c. of Table 7 of the Boiler Area Source Rule (subpart JJJJJJ) where it is stated "Maintaining the 30-day rolling average…"

Q41. I believe that the intent of the rule is:

1. **CO/O_2 CEMS must be installed, operated and maintained in accordance with paragraphs (a)(1) through (6) of this section.**
2. **An O_2 analyzer system must be installed, operated maintained in accordance with (a)(7) and (d) of this section.**

Please correct me if I am wrong

A. Boiler MACT (subpart DDDDD) has a CO emission limit and an alternative CO CEMS-based limit for most subcategories. A facility has the option to comply with either limit. However, as stated in §63.7525(a)(2), to demonstrate compliance with the alternative CO CEMS emission limit, the source must install a certified CO CEMS and comply, as you indicated, with §63.7525(a)(1) through (a)(6). Also, as stated in §63.7525(a)(2), a source with a certified CO CEMS must comply with the alternative CO CEMS emission limit.

A source complying with the CO emission limit, not installing or having a certified CO CEMS, must install an oxygen analyzer, as indicated in §63.7525(a) and, our intent, that the O_2 analyzer system must be installed, operated and maintained in accordance with §63.7525(d), not §63.7525(a)(7). The O_2 analyzer system required in §63.7525(a) does not required the installation of an oxygen trim system. §63.7525(a)(7) is intended to be applicable only to units with existing oxygen trim systems and probable should be moved out of §63.7525(a) to avoid confusion about the frequency that the source needs to conduct tune-ups.

As defined in §63.7575, an "Oxygen analyzer system" means equipment to monitor oxygen levels. The definition includes oxygen trim systems which are a more complex system of monitors to control the oxygen level, but the rule only requires the source to monitor the oxygen level, not install a oxygen trim system.

Q42. Is it correct that per 40 CFR 63.7525(a), a facility is required to install CO & O_2 monitoring system if the boiler is subject to CO emission limit in Tables 1, 2, or 11 through 13 to this subpart. Also, 63.7525(a)(7), the system is required to include the operation of an oxygen trim system.

A. 40 CFR 63.7525(a) actually requires a facility to install either an oxygen analyzer or an CO/O2 CEMS. 40 CFR 7525(a)(7) does not require a facility to install an oxygen trim system. It only applies to sources that already have an oxygen trim system.

Q43. Per 40 CFR 63.7510(c), a facility which uses a CO CEMS to comply with the emissions standards in Table 2 (see comment 2 above) is exempt from initial CO performance testing and O_2 concentration operating limit requirements specified in Sec. 63.7510(a). In Sec. 63.7525(a)(7), the O_2 level in the trim system must be set at the lowest hourly average O_2 measured during the most recent CO performance testing. If the facility is not required to conduct a performance test, what should they follow to set the O_2 level in the trim system?

A. All existing sources are required to conduct an initial tune-up in which they are required to optimize CO to manufacturer's specification. This would be how they set the O2 level. New sources would optimize CO to manufacturer's specifications during installation, which would set the O2 level.

Q44. O_2 levels in a trim system can vary based on the combustion conditions inside the boiler. For example, the system can be set at 3% O_2 (which is typical for oil fired boilers) but if smoking begins to occur, the O_2 level would be changed to accommodate the issue (i.e., increase O_2). Is this flexibility allowed in the Boiler MACT?

A. Yes, this flexibility is allowed. The rule only required that a minimum O2 level be maintained.

Q45. I think the intent is that O2 trim systems are an option for monitoring, but not required. The rule clearly exempts the CO CEMs options from the oxygen concentration limits, but §63.7525 relates specifically to the monitoring requirements if you choose a CO CEMs which requires in section 7 the use of an O2 trim system.

A. Compliance with the CO emission limits is demonstrated by a performance test and maintaining the operating limit (oxygen level) OR, as an alternative, by a certified CO CEMS complying with the alternative CO CEMS emission standard.

Paragraph 63.7525(a)(7) is intended to refer to units complying by performance tests and with the operating limit (oxygen) in which oxygen is monitored to demonstrate continuous compliance. To remove the confusion, we will need to revise 63.7525(a)(7) by adding something like "If you are not complying with the alternative CO CEMS emission standard and you have an oxygen trim system, you must" at the start of the paragraph.

Q46. We have a client with a No. 6 / n.g. boiler with a CO limit and PM/TSM limit. We'll comply with PM limit. For CO, are we req'd to install an O2 analyzer if we don't have an O2 trim system?

A. Yes, an O2 analyzer is required in order to show continuous compliance with the CO limit (See item 9 of table 4 and item 9 of table 8).

Q47. How do we demonstrate continuous compliance for PM?

A. By monitoring operating load and by maintaining fuel records.

Q48. If we are a heavy liquid major source with boilers >250 mmbtu/hr, and we wanted to install CO/O2 monitors, would we need to go to an alternate method of compliance for using a continuous monitors in lieu of an annual stack test?

A. The answer is yes if certified CO/O2 monitors are installed. This is stated in 63.7525(a)(2):

> ... Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

Section 63.7525(a)(2)(iv) further states:

> Any CO CEMS that does not comply with § 63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

Q49. If the unit has dry controls and the stack test shows compliance with the HCl limit at max biomass, is there just fuel use monitoring for HCl going forward?

A. Yes, assuming that the dry control is not a dry scrubber or does not include any sorbent injection.

Q50. If the unit has a WESP, would it be the same or do we have to monitor something on the quench/pre-scrubber for HCl? If the unit has a wet scrubber I assume that we would monitor flow/pressure drop/pH if we test for HCl after the scrubber and we don't want to do monthly fuel analyses.

A. For a wet scrubber, you would need to monitor flow/pressure drop/pH if tested for HCl after the scrubber. For a WESP, you would need to monitor secondary power input as indicated in item 4(b) of Table 4 if tested for HCl after the WESP.

Q51. Is it possible that there could be NO monitoring for HCl in certain cases like biomass boilers? (e.g., just do an annual stack test and make sure you don't burn a fuel mix that could have more HCl content)

A. Yes, that is correct for HCl. However, it is likely that the source will be monitoring the parameters of any control devices required to comply with other emission limits.

Q52. For Hg would the monitoring be whatever they are doing for PM if there is no ACI?

A. Yes

Q53. At one of our company locations, we have 3 biomass wet stoker boilers (different sizes and ages) that all exhaust to a common dry ESP. We have a CO CEMS on the ESP stack, but no O2 monitoring at that location at this time. It does not appear that the facility can install individual CO CEMS on each boiler due to the exhaust stack configuration.

1. Can we use this single CO CEMs for compliance with the CO limit when two or more boilers are operating at the same time (assuming we add an O2 monitor near the CO monitor)? I know that averaging is allowed for PM and other pollutants, but a speaker at the recent NCASI Boiler MACT Workshop stated that the single CO CEMS would be allowed if all the boilers were in the same subcategory.

2. 63.7525(a)(2) states that any boiler that has a CO CEMS that is compliant with the performance specs … must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard. Does the presence of the existing CO monitor downstream of the ESP on the combined boiler exhaust cause the facility to have to comply with the CO CEMs even if facility cannot average CO emissions as per question 1? It would seem to me that if the existing CO CEMS cannot be used as is to monitor CO for the combined boilers, then it should not cause the facility to have to comply with the CO CEMs requirement.

A. A single CO CEMs is allowed to demonstrate compliance with the CO CEMS-based limit when two or more boilers in the same subcategories are vented through a common stack providing the common stack does not receive emissions from units in other subcategories or categories. §63.7522(i) pertains to how emissions from a common stack is treated when used with other stack emissions in emission averaging, not as a separate emission source.

In response to your second question, since, as stated above, it is acceptable to treat a common stack as a single source, providing all units are in the same subcategory, §63.7525(a)(2) does state that any boiler that has a CO CEMS that is compliant with the performance specs … must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard.

REPORTING AND RECORDKEEPING

Q54. Is there a limit on how far back someone could go to claim previous test data that satisfies initial compliance in DDDDD.

A. There isn't a limit on how far back someone could go to claim previous test data that satisfies initial compliance in DDDDD? Of course, they would need to show the operating conditions are the same and that the test met all the rule requirements.

Q55. Would a record be considered "on-site" as long as it's kept anywhere on the facility, or accessed through the network at some computer somewhere on the facility? The question is because the records are not kept at the boiler rooms, but electronically on a network, and there are no computers at the boiler rooms.

A. Yes, anywhere on the facility would be considered “on-site” as long as an inspector would be able to have access to the record in the event of an inspection.

Q56. What needs to be done for the major source Boiler MACT for boilers that are being decommissioned prior to the compliance date of 2016? What about after the compliance date of 2016? Any notification or reporting requirement for these units prior to being decommissioned or after they go away? These units are gas fired, so only subject to tune-ups.

A. The facility would need to submit an initial notification and conduct the required tune-up and energy assessment for any unit that would still be in operation on the compliance date of the rule (January 31, 2016).

Q57. When do recordkeeping requirements start? After initial notification is sent, for new or existing? Already started the day of publication of the rule for existing? The date of startup for new?

A. The recordkeeping requirements start whenever the record is created, so for example if the requirement is to retain a copy of a notification, you would retain it from when the notification is submitted until the appropriate amount of time required by the rule has elapsed. If the requirement is to track fuel usage for a calendar year, you would keep records starting at the beginning of the calendar year (i.e. January 1) and retain them for the required amount of time.

Q58. Does a facility need to resubmit their initial notification if they submitted a notification for 5D back in 2005 before the rule was stayed?

A. Assuming nothing substantive has changed in the information already submitted the earlier notification is sufficient.

Q59. Case-by case MACT limits for SR5 are more stringent than Boiler MACT. This facility conducted initial compliance test (on both wood and coal) in November 2006 and the stack test results demonstrated compliance with the emission limits for PM, Hg and HCl. Subsequent tests (on wood only) also demonstrated compliance with the emission limits. Most recent test was conducted in April 2012.

Per Section 63.7545, they are required to submit the “Notification of Compliance Status” report. Can they include performance test results from 2006 in the report? Boiler MACT has additional requirements such as tune-up and one-time energy assessment, which they have to comply by the final compliance date of January 31, 2016.

A. Yes, a previously conducted emissions test can be used for demonstrating initial compliance providing it was conducted according to §63.7520(b) and (c) and Tables 5 and 7 and the facility has maintained adequate records to document the test.

Q60. 40 CFR 63.7535(d) - You must report all periods when the monitoring system is out of control in your annual report. --- I believe this should be semi-annual report. See Section 63.7550(b) and (c).

A. You are correct, §63.7535(d) should say “semi-annual” instead of “annual.”

Q61. There isn’t a limit on how far back someone could go to claim test data that satisfies initial compliance in DDDDD, is there? I didn’t see anything. Of course, they would need to show the operating conditions are the same and that the test met all the rule requirements. Also, it seems to me that it wouldn’t be an alternative compliance, just the data submitted for initial compliance, right? The region wouldn’t need to waive a test under the General Provisions, they would just be accepting old test data, and since the rule doesn’t have a limit on how old, that wouldn’t require an alternative testing decision, right?

A. In the Boiler Area Source rule, 6J, in 63.11225(a)(5), using previously conducted emission tests in the NOCS is addressed, but no time limit is given. In the Boiler MACT, 5D, there is no similar statement. If the previously conducted test meets all the necessary requirements (i.e., fuel analysis, if required; setting operating limits) it can be used for initial compliance without requiring an alternative testing decision. The rule only states that you must comply by January 31, 2016. However, the Notification of Compliance Status is required to be submitted before the 60^{th} day following the completion of all performance test and/or other initial compliance demonstrations fo all boilers and process heaters at the facility (see §63.7545(e)).

Q62. The revised Boiler MACT rules published in the FR on 1/31 and 2/1/13 specified revised deadlines for submittal of the initial notification for existing units. The major source deadline is May 31, 2013 and the area source deadline is January 20, 2014. Could you please confirm that facilities that have already submitted their initial notifications to EPA and the state agency do not need to resubmit the notifications before these revised deadlines?

A. Yes, facilities that have already submitted their initial notifications, as required by the March 2011 final rule, do not need to resubmit the notifications as a result of the amended deadlines.

START-UP AND SHUTDOWN

Q63. The definition of startup is clear until you read "or for any other purpose," which could pretty much refer to anything. Specifically, my question is regarding new boilers. When a new boiler is installed, the contractor will generally start the boiler to perform an initial tune-up and test the boiler to make sure that it works fine. The intent there is not to supply heat or steam for heating or electricity. Then the boiler is turned over to the owner and he will then start it for normal operations to supply heat or steam for heating or electricity. The question is then, is the date of startup considered the date of the first startup by the contractor who started-up the boiler for testing to ensure it works, or is the official date of startup the date that the owner starts the boiler to use it in regular operations for heating or electricity supply?

> A. An EPA guidance document "Instruction Manual for Clarification of Startup in Source Categories Affected by New Source Performance Standards" (EPA-68-01-4143)[1] lists "pre-startup" activities that are done as part of installing a new boiler. There is a distinction between installation activities and actual startup. So, hot water or steam leaving the boiler - to complete the purpose of the boiler (i.e. provide hot water or steam to heat a building) - would be startup. However, hot water or steam leaving the boiler as part of a "pre-startup" or installation procedure would not be startup.

Q64. I have many clients whose boilers are not used to run process equipment or generate electricity. They are used to heat water or produce steam to heat buildings. So, if the same logic applies, once hot water leaves the boiler or once steam provides heat to a building, start up has commenced. Correct?

> A. Your statement is generally correct. However, based on an EPA guidance document (See footnote to Q64), "pre-startup" activities that are done as part of installing a new boiler, because they would be completed before startup, would not be counted in the 48 hours included in the rule. There is a distinction between installation activities and actual startup. So, hot water or steam leaving the boiler - to complete the purpose of the boiler (i.e. provide hot water or steam to heat a building) - would be startup. However, hot water or steam leaving the boiler as part of a "pre-startup" or installation procedure would not be startup.

Q65. If a facility vents steam during startup of a boiler, would the period the time when steam is vented and not used in the process for heating or electrical generation be considered part of the startup period?

> A. Venting steam is not considered to mean supplying steam; thus, venting steam does not trigger the end of startup.

[1] http://www.epa.gov/ttnnaaqs/aqmguide/collection/t5/nspsaffsource.pdf

Q66. Does the obligation to utilize clean fuels during the Startup period require that only clean fuels be utilized throughout this period? Can solid fuels be utilized during the startup process as long as the pollution control devices are in operation?

A. Yes. Non-clean fuels (e.g., solid fuels) can be fired during startup, but the source must engage the applicable control devices, except for those devices listed in the rule.

Q67. My question concerns startup of an existing coal or biomass boiler. In the preamble to the rule, it states "For startup, you must use one or a combination of the listed clean fuels". The rule again lists the above statement and then lists the clean fuels, which I am assuming is an all inclusive list. My question is if it is allowable to lay a bed or coal or biomass in a boiler prior to startup. Based on how I read the rules, I would say no; but due to the enormous costs of equipment changes, I need to have this verified. Please reply back when you have an opportunity.

A. The list of clean startup fuels is an all inclusive list. However, our intent of the work practice requirement is to allow sources to lay a bed of coal or biomass in a boiler prior to startup if the bed would be ignited using a listed clean fuel.

The second part of that work practice is "If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable control devices except …". In this section, our intended meaning of "firing" is the feeding of fuel into the boiler once startup has been initiated, not ignition of a preexisting bed.

OPERATING LIMITS

Q68. An Iowa facility pointed out to me what seems to be some inconsistency in the Boiler MACT, regarding the SO2 operating limit for a boiler using SO2 CEMS to demonstrate continuous compliance with the HCl limit. Several places in the MACT indicate that the SO2 operating limit is based on the highest level measured during the performance test, but Tables 7 and 8 indicate that the limit is the lowest level measured during the test. The rule citations are listed below. I'm looking for confirmation that the correct SO2 operating limit is the <u>highest</u> hourly average SO2 concentration measured during the most recent HCl performance test.

A. The correct SO2 operating limit is the <u>highest</u> hourly average SO2 concentration measured during the most recent HCl performance test, as stated on page 7143 of the preamble to the January 31, 2013 final amendments. The preamble statement is:

> "Boilers or process heaters subject to an HCl emission limit
> that demonstrate compliance with an SO2 CEMS would be required to
> maintain the 30-day rolling average SO2 emission rate at or below the highest

hourly average SO_2 concentration measured during the most recent HCl performance test."

So, 63.7530(b)(4)(viii) and item 10 of Table 4 are correct. The others will need to be revised.

IMPLEMENTATION: ENERGY ASSESSMENT

Q69: How is heat input capacity calculated for <u>each affected boiler</u>?

A. Heat input capacity for each boiler is calculated based on 8760 hours per year.

Q70: How is heat input capacity for <u>facilities with affected boilers</u> calculated for the purpose of determining which heat input capacity thresholds and associated maximum on-site technical labor hours in the definition of "Energy assessment" apply to the facility's energy assessment (e.g., for facilities with affected boilers with less than 0.3 trillion Btu/year heat input capacity, the assessment will be 8 on-site technical labor hours in length maximum)?

A. Facility heat input capacity is calculated by adding together the heat input capacity for each boiler subject to the energy assessment requirement.

Q71. I would like to get clarification on the wording that is in the definition for the energy assessments in DDDDD and JJJJJJ. I have heard two different interpretations. As an example:
For facilities with a combined heat input capacity of < 0.3 trillion BTU/yr, the boiler systems and any on-site energy use systems accounting for at least 50% of affected boilers energy production must be evaluated.

So as an example:

If a facility has a single boiler that provides steam to ten end uses with each end use accounting for about 10%.

- **First interpretation: The boiler and five of the end uses would need to be evaluated (since 5 of them add up to 30%)**
- **Second interpretation: Only the boiler would need to be included since none of the end uses exceeds the 50% threshold.**

Which interpretation is correct?

A. The second interpretation would be correct in the example situation.

Q72. The reason I write is to ask for more guidance on how to calculate the value of the term "combined heat input" as used in the Area and Major HAP source boiler MACTs. As you know, facilities must calculate this value to determine the requirements of their "One Time Energy Assessment" required by this MACT.

When calculating this value, should folks with affected boiler use one of the two schemes below?
1) Calculate "combined heat input" assuming that all affected boilers (except limited use boilers) operate the same annual amount that the facility assumes they operate annually when the facility calculates their Potential to Emit for HAPs.
2) Calculate "combined heat input" assuming that affected boiler operating hours (except limited use boilers) equal the actual amount of hours that the boilers operated in some previous year.

A. Heat input capacity for each affected boiler is calculated based on 8760 hours per year. For the purpose of determining which heat input capacity thresholds and associated maximum on-site technical labor hours in the definition of "Energy assessment" apply to the facility's energy assessment, "combined heat input" is calculated by adding together the heat input capacity for each boiler subject to the energy assessment requirement. That calculation differs for the Major Source Boilers Rule and the Area Source Boilers Rule. Specifically, under the Major Source Boilers Rule, all existing boilers are subject to the energy assessment requirement so heat input capacity for all existing boilers at a major source facility would be included in the "combined heat input" calculation. Under the Area Source Boilers Rule, only existing boilers with heat input capacity equal to and greater than 10 MMBtu/hr are subject to the energy assessment requirement so heat input capacity for only those specific existing boilers at an area source facility would be included in the "combined heat input" calculation.

RESOURCES FOR MORE INFORMATION

Q73. Where can I get additional information?

A. Additional information on the proposed and final rules, implementation and compliance information and forms is available from the following EPA websites:

EPA Area source boiler webpage, www.epa.gov/boilercompliance
Combustion Portal, http://www.envcap.org/boiler/
EPA combustion webpage, www.epa.gov/airquality/combustion/actions.html
EPA boiler webpage, www.epa.gov/ttn/atw/boiler/boilerpg.html