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Via electronic mail and Federal Express May 6, 2015

Honorable Gina McCarthy
Administrator, U.S. EPA
William Jefferson Clinton Federal Building
1200 Pennsylvania Avenue, NW
Washington, DC 20460
McCarthy.Gina@epa.gov

Dear Administrator McCarthy:

Please find attached (1) Sierra Club's Petition to Object to the Issuance of a State Title V Operating Permit issued by the Arkansas Department of Environmental Quality for Entergy Arkansas, Inc.'s White Bluff Power Plant, Permit No. 0263-AOP-R8 and (2) Exhibits A-H. A hard copy with a disk of Exhibits will follow by overnight Federal Express. Also arriving by overnight Federal Express is a copy of the Petition.

If you have any questions, do not hesitate to contact me.

Sincerely,

/s/ Tony G. Mendoza

Tony G. Mendoza
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San Francisco, CA 94105
(415) 977-5589
(415) 977-5793 fax
tony.mendoza@sierraclub.org

cc: Ron Curry, Regional Administrator, U.S. EPA Region VI
Thomas Rheaume, Arkansas Department of Environmental Quality
Barry Snow, Senior Lead Environmental Specialist, Entergy Arkansas, Inc.

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EXTERNAL AFFAIRS DIVISION

UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY

BEFORE THE ADMINISTRATOR

In the Matter of	)	
	)	
Proposed Clean Air Title V Operating Permit	)	
Issued to Entergy Arkansas, Inc.to Operate	)	Petition for Objection
White Bluff plant	)	
	)	Permit No. 0263-AOP-R8

Sierra Club hereby petitions the Administrator of the United States Environmental Protection Agency ("EPA"), through Clean Air Act Section 505(b)(2) (42 U.S.C. § 7661d(b)(2)), to object to the proposed Title V Operating Permit[1] reissued on January 22, 2015 by the Arkansas Department of Environmental Quality ("ADEQ") for the White Bluff plant operated by Entergy Arkansas, Inc. ("Entergy Arkansas").

The Administrator must object to the issuance of the White Bluff Title V permit because it fails to meet the requirements of the Clean Air Act, the Arkansas State Implementation Plan, and applicable regulations for at least these reasons:

(1) ADEQ's technical justification for the activated carbon injection project is fundamentally flawed and, contrary to ADEQ's conclusion, particulate matter ("PM") emissions are likely to increase significantly as a result of this project, which should have triggered New Source Review ("NSR") and the application of Best Available Control Technology ("BACT") emission limits to this source;

(2) ADEQ failed to perform any air dispersion modeling or other analysis to demonstrate that the modified White Bluff plant would not violate the National Ambient Air Quality Standards ("NAAQS") for particulate matter or other pollutants;

(3) NSR violations, alleged by Sierra Club in a January 2010 Petition to Object, remain unaddressed and the White Bluff plant continues to operate without the required BACT emission limits;

[1] Proposed White Bluff Title V Permit, Ex. A.

(4) The proposed White Bluff permit unlawfully excludes substituted data from assessment of compliance with emission limits; and

(5) The proposed White Bluff permit fails to allow for enforcement and accountability as it does not describe the applicable Mercury and Air Toxics Standards ("MATS") requirements for which the White Bluff plant intends to comply.

I. Petitioner

Sierra Club is the nation's oldest and largest grassroots environmental organization. Sierra Club's mission is to explore, enjoy, and protect the wild places of the earth, and to educate and enlist humanity to protect and restore the quality of the natural and human environment. Sierra Club has worked diligently to protect and improve air quality in the United States, limit the adverse effects of climate change, and promote clean energy.

Sierra Club members in Arkansas have a strong interest in protecting and enhancing the quality of ambient air in their state and the entire region. Sierra Club members reside, work, visit and use natural resources in the same region as the White Bluff plant and those members' aesthetic, recreational, environmental, economic and health-related interests will be injured and otherwise adversely impacted if the White Bluff plant is allowed to continue to operate and emit air pollutants at the levels contemplated by the challenged proposed Title V permit.

II. Background

The White Bluff plant is a 1700 megawatt coal-fired electric generating facility located in Redfield, Arkansas. The plant consists of two units that began operation in 1980 and 1981, respectively. Entergy Arkansas operates the White Bluff plant.

The proposed White Bluff Title V permit is a renewal of the facility's operating permit. Entergy Arkansas initiated the instant permitting proceeding by filing an application to modify the White Bluff plant's Title V permit to incorporate the requirements of the "National

Emissions Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units," also referred to as the MATS rule (40 C.F.R. Part 63, Subpart UUUUU).[2]

Entergy Arkansas proposed to achieve compliance with the MATS rule through installation of an activated carbon injection ("ACI") system.[3] ADEQ describes Entergy Arkansas's ACI system as follows:

> Compliance with MATS will result in the installation of additional emissions controls on each of the Unit 1 and Unit 2. The primary emission control unit will be an activated carbon injection (ACI) system. The ACI system will use either brominated activated carbon or non-halogenated activated carbon that is injected post combustion. If non-brominated activated carbon is used by the ACI then a separate halide solution would be applied to the coal prior to combustion.[4]

There is no evidence in the record that ADEQ has required Entergy Arkansas to decide which type of sorbent to use in the ACI system.[5]

Entergy Arkansas theorized that the presence of bromine will increase the efficiency of the White Bluff electrostatic precipitators and reduce PM emissions.[6] Relying on Entergy Arkansas's analysis, ADEQ concluded that PM emissions would decrease by over 73 tons per year and PM_{10} emissions would decrease by over 15 tons per year due to the installation of the ACI system.[7] Because ADEQ found that this permit renewal did not involve an emissions increase over the previous Title V permit, ADEQ performed no evaluation of the modified White Bluff plant's compliance with the NAAQS.[8]

On June 11, 2014 and June 29, 2014, ADEQ gave notice of its draft permitting decision for this White Bluff Title V renewal permit. On July 11, 2014, Sierra Club submitted initial

[2] ADEQ Statement of Basis at 1, Ex. B.
[3] *Id.*
[4] Proposed White Bluff Title V Permit at 5.
[5] ADEQ Statement of Basis at 1.
[6] Proposed White Bluff Title V Permit at 5.
[7] ADEQ Statement of Basis at Appendix A.
[8] ADEQ Statement of Basis at 3.

comments regarding ADEQ's proposal to reissue the Title V permit for the White Bluff plant.[9] And, on August 14, 2014, Sierra Club timely submitted supplemental comments.[10]

After making some changes from the draft permit, ADEQ issued this proposed Title V permit on January 22, 2015. Assuming that EPA's review period began that same day,[11] this Petition to Object is timely filed within 60 days of the conclusion of EPA's review period. *See* 42 U.S.C. § 7661d(b)(2).

III. Legal Standards

Title V of the Clean Air Act, 42 U.S.C. §§ 7661-7661f, prohibits any person from operating a major stationary air pollution source such as the White Bluff plant without an operating permit. A Title V operating permit must include all applicable requirements, including all applicable emission limitations and standards, and must include provisions assuring compliance with those requirements. *See* 42 U.S.C. § 7661c(a), 40 C.F.R. § 70.1(b), APCEC Reg. 26.402(4)(a) and (8)(a), (b)(iii) and (c)(iii). The federal operating permit regulations provide that "[w]hile title V does not impose substantive new requirements. . .[a]ll sources subject to these regulations shall have a permit to operate that assures compliance by the source with all applicable requirements." 40 C.F.R. § 70.1(b).

The regulations in 40 C.F.R. Part 70, which govern state operating permit programs required under Title V of the Clean Air Act, require Title V permits to assure compliance with all "applicable requirements." The term "applicable requirements" is defined in the federal rules as including any provision of the state implementation plan ("SIP"), any term or condition of a preconstruction permit issued pursuant to regulations approved under Title I of the Clean Air Act

[9] Sierra Club Initial Comments on Draft White Bluff Permit, Ex. C.
[10] Sierra Club Supplemental Comments on Draft White Bluff Permit, Ex. D.
[11] Sierra Club has been unable to confirm when Region VI's review period began for this permit renewal.

including under Parts C and D of the Act, any standard or requirement under Sections 111, 112, 114(a)(3), or 504 of the Act, as well as the Act's Acid Rain program requirements. 40 C.F.R. § 70.2; APCEC Reg. 26, Chapter 2 (definition of "applicable requirement").

"If any [Title V] permit contains provisions that are determined by the Administrator as not in compliance with the applicable requirements of this chapter…the Administrator *shall*…object to its issuance." 42 U.S.C. § 7661d(b)(1) (emphasis added). EPA "does not have discretion whether to object to draft permits once noncompliance has been demonstrated." *See N.Y. Pub. Interest Group v. Whitman*, 321 F.3d 316, 334 (2nd Cir. 2003).

IV. Grounds for Objection

A. The Technical Justification for the Activated Carbon Injection Project and the Claim That this Project Will Not Increase PM Emissions Is Flawed and Incomplete and, In Fact, PM-10 Emissions Are Likely To Exceed the NSR Significance Levels and Trigger the Requirement to Obtain an NSR Permit and Apply BACT.

EPA must object to the issuance of the White Bluff Title V permit because the ADEQ's technical justification for accepting Entergy Arkansas's claims that PM emissions would not increase is flawed. Sierra Club retained an expert with extensive experience evaluating coal plant operations, Dr. Ranajit (Ron) Sahu, to evaluate Entergy Arkansas's assertion that PM emissions will decrease following the addition of ACI to its operations at the White Bluff plant. Dr. Sahu's July 2014 Technical Comments,[12] August 2014 Technical Comments,[13] and his April 2015 Technical Comments[14] are incorporated herein.

Dr. Sahu concludes that Entergy's technical support for its ACI project is fundamentally flawed in numerous ways and is based on unreliable and insufficient technical information and

[12] Sahu July 2014 Technical Comments, Ex. E.
[13] Sahu August 2014 Technical Comments, Ex. F.
[14] Sahu April 2015 Technical Comments, Ex. G.

documentation. Without significantly more reliable and comprehensive technical support for this project, ADEQ should not have accepted Entergy Arkansas's assertion that particulate matter emissions will decrease as a result of the addition of ACI. Dr. Sahu concludes that, contrary to Entergy Arkansas's assertions, the best evidence shows that PM emissions are likely to significantly increase, triggering NSR and the application of BACT emission limits.

According to Dr. Sahu, Entergy Arkansas's technical support for its claimed reduction in PM is flawed in at least seven important ways:

- First, Entergy Arkansas provides no details on the basic design parameters of the electrostatic precipitators ("ESPs") at White Bluff Units 1 and 2. This information is critical to any review regarding the performance of the ESPs with the addition of an ACI system at the White Bluff plant.[15]

- Second, Entergy Arkansas does not state how much sorbent (or which type) will be used in order to reduce mercury emissions to below the MATS levels. In fact, no mercury testing data has been provided at all. Thus, there is no data to show that a specific ACI process would lead to the necessary mercury reductions. Obviously, ACI runs that do not achieve the MATS-required mercury reductions are useless for assessing PM emissions since Entergy Arkansas must comply with the MATS requirements for mercury.[16]

- Third, the June 2012 tests on White Bluff Unit 1 are unreliable as the gas flow rates indicated that Unit 1 was operating at much reduced capacity during these tests thereby invalidating the tests' usefulness to predict emissions at full capacity. In addition, White Bluff Unit 2 operates at much higher heat input rates than Unit 1 and thus Entergy Arkansas's attempt to extrapolate results from Unit 1 to Unit 2 is not reasonable.[17]

- Fourth, Entergy Arkansas's failure to reasonably determine baseline PM emissions undermines its prediction of an emissions decrease. The identified wide range of possible PM baselines indicates that PM emission could increase, even under Entergy Arkansas's flawed analysis.[18]

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[15] Sahu July 2014 Technical Comments at 1-2.
[16] *Id.* at 2.
[17] *Id.*
[18] *Id.* at 3.

- Fifth, the EERC tests provided by Entergy Arkansas are not reliable because they were performed at an entirely different ESP, with different design parameters, and with no showing as to why these results could be achieved at the White Bluff ESPs.[19]

- Sixth, Entergy Arkansas has not provided the inputs and assumptions used in the Aurora model that it used to estimate projected future emissions of all relevant pollutants. Entergy Arkansas used this model to create projected heat input figures for Units 1 and 2. These heat input figures were then used by Entergy Arkansas for all of its future emissions calculations. Without the inputs and assumptions used to generate the heat input figures, the emissions calculations themselves are not verifiable or even understandable.[20]

- Seventh, for a given future year, Entergy Arkansas has adjusted (by roughly 5%) the Aurora projected heat input estimate to account for a "discrepancy" between how Entergy reports heat input to the U.S. EPA Clean Markets Division versus what Entergy Arkansas believes the "accurate" heat input figure should be. In any case, in order to make this adjustment, Entergy Arkansas states that it derived purportedly more accurate heat input numbers from fuel usage at each White Bluff unit and the heating value of the fuel(s). But Entergy Arkansas provides only its final heat input values without any data to support the fuel usage and heating value inputs. Nor does Entergy Arkansas provide any discussion as to why the heat input calculated from these parameters would be more accurate than the figures reported to U.S. EPA.[21]

On the basis of these considerations, Dr. Sahu rejected Entergy Arkansas's conclusion that PM emissions were likely to decrease. To the contrary of Entergy Arkansas's claims, the available evidence demonstrates that the proposed ACI project will likely cause a collective increase of approximately 22.8 tons per year of emissions of filterable PM_{10} from the White Bluff plant.[22] This 22.8 tons per year increase triggers NSR applicability and the requirement to

[19] *Id.* at 3-6. Given all the variables involved, it is extremely unlikely that the White Bluff, Independence, and the EERC ESPs would all have the same PM removal efficiencies as Entergy Arkansas claims and assumes. Entergy Arkansas's claim in this regard is further evidence that their tests are not reliable.
[20] Sahu August 2014 Technical Comments at 1-2.
[21] *Id.*
[22] Sahu July 2014 Technical Comments at 5; Sierra Club Initial Comments on Draft White Bluff Permit at 2-3.

apply BACT to the White Bluff plant.[23] On this basis alone, the Administrator should object to the issuance of the proposed White Bluff Permit. As Dr. Sahu pointed out in his July 2014 Technical Comments, a conservative estimate shows significant PM increases:

> What is clear is that with ACI addition, the particulate loading into the ESPs will increase. The Road Emission Calculations spreadsheet provided by Entergy states that the maximum annual ACI Injection Rate (or usage) will be 2,278 tons/year for both units. Assuming an ESP filterable PM efficiency of 99% (which is generous, given the total lack of information on ESP design, condition, and operating parameters) for each ESP, the incremental emissions of filterable PM as a result of the additional ACI loading is 2,278*(1-0.99) = 22.8 tons/year. In addition, as Entergy notes, there will be additional increases in fugitive PM emissions as a result of road traffic, ash hauling, ACI transport, etc. Collectively, the expected increase in filterable PM emissions, therefore, is likely to be above 22.8 tons/year. This exceeds the PSD Significant Emissions Rate for PM10, which is 15 tons/year. Thus, it is more likely than not that the addition of ACI, as proposed by Entergy for White Bluff Units 1 and 2, will trigger PSD review for this pollutant. This means that the application and permit are incomplete, since Entergy has not provided a BACT analysis, or any ambient air quality modeling analysis, or any of the other PSD application requirements (such as impacts to Air Quality Related Values), *etc.*[24]

Having received these comments on the draft White Bluff permit, ADEQ made no changes and required no further analysis from Entergy Arkansas regarding the ACI project. Instead, in its response to comments, ADEQ asserted that Sierra Club "provides no definitive information to refute Entergy's analysis."[25] As Dr. Sahu observes in his April 2015 Technical Comments, however, ADEQ's response purports to reverse the burden of persuasion for this permitting proceeding.[26] Having itself relied on an inadequate analysis that is rife with data gaps to accept Entergy Arkansas's conclusion, ADEQ now seeks to apply a much more rigorous

[23] *See* 40 C.F.R. § 52.21(b)(23)(i).
[24] Sahu July 2014 Technical Comments at 5.
[25] ADEQ Response to Comments at 2, Ex. H.
[26] Sahu April 2015 Technical Comments at 3.

standard for the concerned public, which of course lacks access to Entergy Arkansas's operations and data.

In his April 2015 Technical Comments, Dr. Sahu refutes ADEQ's other responses on this ACI issue:

- First, ADEQ argued that design parameters for the White Bluff ESPs were "irrelevant" because Entergy Arkansas provided "actual trial testing of ACI."[27] As demonstrated above, this "actual trial testing" occurred when the unit was running at significantly reduced load. Dr. Sahu notes that ADEQ's statement is further undermined by Entergy Arkansas's belated and apparently non-binding pledge to upgrade its ESP "to mitigate any risk of an increase" in PM emissions.[28] Dr. Sahu asks: "Why, if it were so confident that emissions of PM would decrease as noted in its permit application (and as blindly accepted by ADEQ), would the utility propose to "mitigate any risk" of PM emissions via ESP upgrade?"[29]

- Second, ADEQ argued that it was "speculative" that changes in load or ACI injection may affect emission rates and such a relationship is "not relevant" because Entergy Arkansas's analysis was based on "the difference in emission rates with and without ACI, not any total emission rate."[30] As Dr. Sahu observes, ADEQ's response "makes no sense whatsoever."[31] Of course changes in unit operating capacity and/or sorbent-injection rates will affect the resultant emission rates and the total mass of PM emissions from any test. The problem here is, in part, that ADEQ has relied on tests that did not occur during representative unit operating conditions.[32]

- Third, ADEQ took issue with Dr. Sahu's estimate of PM emissions arguing that "it is not possible to estimate an emission rate" by applying ESP efficiency to bulk activated carbon.[33] Dr. Sahu responds that "ESP efficiency is widely used to estimate emission rates from ESPs" and other means for estimating PM emissions were unavailable because there was no record evidence of the relationship between particle size and ESP efficiency for the specific White Bluff units.[34] To provide more refined estimates, Dr. Sahu

[27] ADEQ Response to Comments at 3.
[28] Sahu April 2015 Technical Comments at 2.
[29] *Id.*
[30] ADEQ Response to Comments at 3.
[31] Sahu April 2015 Technical Comments at 3.
[32] *Id.*
[33] ADEQ Response to Comments at 3.
[34] Sahu April 2015 Technical Comments at 3-4.

suggests that Entergy Arkansas be required to provide "ESP/PM size versus efficiency curves for each ESP at White Bluff, along with underlying ESP operating parameters."[35]

- Fourth, ADEQ notes that Dr. Sahu had not "quantified or specified" the road emissions associated with the ACI projects.[36] Dr. Sahu responds that no such quantification was possible on this permitting record because ADEQ had failed to require an adequate record.[37]

In sum, Sierra Club contends that, based upon the available evidence, there was no basis for ADEQ to accept Entergy Arkansas's assertion that particulate matter emissions will decrease due to the planned installation of ACI at the White Bluff plant. In fact, that the addition of ACI will likely increase PM_{10} emissions at the White Bluff plant is sufficient to trigger PSD review for this pollutant. For these and all the reasons discussed in Sierra Club's comments to ADEQ and Dr. Sahu's technical comments, the Administrator must object to the issuance of this proposed White Bluff permit. In doing so, the Administrator should require that Entergy Arkansas and ADEQ provide a more adequate record for assessing the impact of the ACI project on PM emissions.

B. The Proposed White Bluff Permit Cannot Lawfully Be Issued Because No Adequate Demonstration Has Been Performed, and ADEQ Has No Reasonable Basis for Concluding, That the White Bluff Plant and the Proposed Changes to be Made Thereto, Will Not Violate the PM NAAQS.

As explained above, the ACI project covered by the proposed White Bluff permit is likely to result in an increase in PM emissions of over 22 tons per year, which is sufficient to trigger NSR applicability and a requirement to perform air dispersion modeling. Further, under the Arkansas SIP, without a determination by ADEQ that the modified White Bluff plant will not cause a violation of a NAAQS (or any other applicable emissions limitation), the proposed White

[35] *Id.*
[36] ADEQ Response to Comments at 3.
[37] Sahu April 2015 Technical Comments at 4.

Bluff permit should not have been issued. The Administrator should object to the issuance of the proposed White Bluff Permit on this issue as well.

Despite the analysis showing significant PM increases, neither ADEQ nor anyone else has performed any air modeling analysis or other comparable demonstration to show that the White Bluff plant and the proposed modification projects covered by the proposed White Bluff permit will not interfere with attainment of the NAAQS or otherwise cause air pollution that is harmful to human health.[38] There are many provisions under the Clean Air Act and the Arkansas SIP that require air modeling in this situation or at least some substantive demonstration that NAAQS attainment will not be interfered with and that injurious air pollution will not result as a consequence of this permit. *See* APCEC Reg. 18.302; APCEC Reg. 19.402; APCEC Reg. 19.502; APCEC Reg. 26; Clean Air Act Section 110(a)(2)(C); 40 C.F.R. § 51.160-51.164.

Sierra Club understands that in April 2013, the Arkansas Legislature and governor enacted a new law, Act 1302, that prohibits ADEQ from requiring a permit applicant to submit air quality modeling to demonstrate compliance with the NAAQS, and from undertaking its own modeling or even considering modeling submitted by a third-party without the applicant's consent. Sierra Club further understands that ADEQ's previous practice of conducting air quality modeling for Title V permit renewals was integral to its strategy for assuring compliance with the NAAQS. Indeed, Act 1302 now requires ADEQ to develop "NAAQS state implementation plans," presumably to fill the gap left in Arkansas's plan for assuring compliance with the NAAQS given that ADEQ is no longer permitted to follow its previous practices.

Combined with the flawed NSR applicability analysis submitted by Entergy Arkansas, ADEQ has not satisfied SIP requirements to ensure that the NAAQS are attained and that public

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[38] Statement of Basis at 3.

health is protected. The Administrator must object to the issuance of this permit to assure that this serious deficiency is corrected.

C. New Source Review Violations at the White Bluff Plant Remain Unaddressed and Therefore the White Bluff Plant Continues to Operate without the Required BACT Emission Limits and Other NSR Requirements.

On January 28, 2010, EPA received Sierra Club's Petition to Object to the issuance of an earlier version of the White Bluff Title V permit (0263-AOP-R7). Sierra Club hereby incorporates the allegations of the January 2010 Petition here. In the January 2010 Petition, Sierra Club alleged that turbine efficiency projects and other modifications on both White Bluff units constituted major modifications that caused significant emissions increases and should have triggered NSR review, including the requirement to incorporate BACT emission limits into the Title V permit. Sierra Club's January 2010 Petition remains "pending" before the Administrator.[39] The Administrator should object to the issuance of the instant Title V permit renewal for the White Bluff plant because this permit is deficient as the White Bluff plants continues to operate in violation of NSR requirements.

D. The Proposed White Bluff Permit Unlawfully Excludes Substituted Data From Compliance Assessment.

In response to comments from Entergy Arkansas, ADEQ revised the permit to exclude substituted data-—estimates created when the continuous emissions monitors ("CEMS") are not operating—from determining whether the White Bluff plant is complying with applicable emissions limits.[40] ADEQ provided no explanation when it accepted Entergy Arkansas's

[39] *See* http://yosemitel.epa.gov/r6/Apermit.nsf/AirP?OpenView#M
[40] *See* ADEQ Response to Comments at 9.

suggestion to limit the use of substituted data in the two specified instances: Specific Conditions 4 and 5.[41]

ADEQ's acceptance of Entergy Arkansas's suggestion is improper as it eliminates the utility's incentive to properly operate its CEMS.[42] The purpose of the substituted data requirements is to encourage a source to maintain its CEMS equipment in valid, operational conditions at all times—so that it does not have to rely on the missing data. ADEQ's acceptance of Entergy Arkansas's request to exclude substituted data from assessing compliance destroys this incentive. The exclusion of substituted data from use in determining compliance therefore undermines the purpose of a Title V permit: to allow for accountability and compliance with all applicable requirements. The Administrator should object to the issuance of the White Bluff permit based on this issue as well and reverse ADEQ's acceptance of this relaxation in permit requirements.

E. The Proposed White Bluff Permit Should Not Be Issued Due to a Lack of Enforceability and Specificity Concerning the Identification of the Applicable Requirements for the MATS rule.

The purpose of a Title V operating permit is, in part, to allow the public to assess a facility's compliance with all applicable requirements. *See generally* APCEC Reg. 26.402(B)(3)(e)-(h), (4), (5) and (7). The MATS standards will be applicable requirements for this facility beginning in April 2016. EPA's MATS regulation allows sources to comply in several different ways; for example, a source can choose to comply with either a limit on sulfur dioxide (SO_2) or acid gases (HCl). However, this choice cannot be an ongoing one without undermining the very purpose of Title V. *See, e.g., Sierra Club v. Johnson*, 541 F.3d 1257, 1260 (11th Cir. 2008) (Title V added "clarity and transparency" to the permitting process "to help citizens, regulators,

[41] *Id.*

[42] *See* Sahu April 2015 Technical Comments at 5-6.

and polluters themselves understand which clean air requirements apply to a particular source of air pollution."); *see id.* ("The goal is 'increased source accountability and better enforcement.") (quoting "Operating Permit Program," 57 Fed. Reg. 32250, 32,251 (July 21, 1992)).

The proposed White Bluff permit incorporates the MATS limits in Section IV, ¶ 32, retaining the "either/or" option for the three different basic categories of MATS limits. Such a permit structure materially deprives the public of an opportunity to track the plant's compliance. Under this framework, the facility is effectively free to choose (even, perhaps, years after the fact) among the alternative compliance methods on its own without any notice to ADEQ or the public. These permit conditions are therefore unenforceable. Accordingly, the Administrator should object to the issuance of this permit and incorporate into the White Bluff Permit the specific MATS limits for which Entergy Arkansas intends to comply.

V. Conclusion

For the foregoing reasons, Sierra Club respectfully requests that the Administrator object to the issuance of this White Bluff Title V permit.

Dated: May 6, 2015

Respectfully submitted,

/s/ Tony G. Mendoza

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Counsel for Sierra Club

Exhibit List for Sierra Club's May 6, 2015 Petition to EPA to Object to the Proposed White Bluff Title V Permit

Exhibit	Description
A	Proposed White Bluff Title V Permit (Jan. 22, 2015)
B	ADEQ Statement of Basis for White Bluff Title V Permit
C	Sierra Club Initial Comments on Draft White Bluff Permit (July 11, 2014)
D	Sierra Club Supplemental Comments on Draft White Bluff Permit (August 14, 2014)
E	Sahu July 2014 Technical Comments
F	Sahu August 2014 Technical Comments
G	Sahu April 2015 Technical Comments
H	ADEQ Response to Comments for White Bluff Title V Permit

ADEQ
ARKANSAS
Department of Environmental Quality

January 22, 2015

Barry Snow, Senior Lead Environmental Specialist
Entergy Arkansas, Inc. (White Bluff Plant)
1100 White Bluff Road
Redfield, AR 72132

Dear Mr. Snow:

The enclosed Permit No. 0263-AOP-R8 is your authority to construct, operate, and maintain the equipment and/or control apparatus as set forth in your application initially received on 6/28/2013.

After considering the facts and requirements of A.C.A. §8-4-101 et seq. as referenced by §8-4-304, and implementing regulations, I have determined that Permit No. 0263-AOP-R8 for the construction and operation of equipment at Entergy Arkansas, Inc. (White Bluff Plant) to be issued and effective on the date specified in the permit, unless a Commission review has been properly requested under Arkansas Department of Pollution Control & Ecology Commission's Administrative Procedures, Regulation 8, within thirty (30) days after service of this decision.

The applicant or permittee and any other person submitting public comments on the record may request an adjudicatory hearing and Commission review of the final permitting decisions as provided under Chapter Six of Regulation No. 8, Administrative Procedures, Arkansas Pollution Control and Ecology Commission. Such a request shall be in the form and manner required by Regulation 8.603, including filing a written Request for Hearing with the APC&E Commission Secretary at 101 E. Capitol Ave., Suite 205, Little Rock, Arkansas 72201. If you have any questions about filing the request, please call the Commission at 501-682-7890.

Sincerely,

Mike Bates
Chief, Air Division

Enclosure: Final Permit

RESPONSE TO COMMENTS

ENTERGY ARKANSAS, INC. (WHITE BLUFF PLANT)
PERMIT #0263-AOP-R8
AFIN: 35-00110

On June 11, 2014 and June 29, 2014, the Director of the Arkansas Department of Environmental Quality ("ADEQ" or "Department") gave notice of a draft permitting decision for the above referenced facility. During the comment period written and oral comments on the draft permitting decision were submitted on behalf of the facility and the public. The Department's response to these issues follows.

Note: The following page numbers and condition numbers refer to the draft permit. These references may have changed in the final permit based on changes made during the comment period.

Commenter	Comments Begins with:	Ends with Comment #
William Moore, Sierra Club	1	4
Entergy	5	26
Chester A. Sautter	27	27
Barbara Jarvis	28	28
Glen Hooks	29	29
Tony Mendoza, Sierra Club	30	33
Robert Walker	34	34
Christina Mullinax	35	35
Mike Brown	36	36
Chris Bodiford	37	37
Rel Corbin	38	38
Shelly Buonaiuto	39	39
Beaux Franks	40	40
Ms. Scharmel Roussel	41	41

Comment #1

The technical justification for the proposed activated carbon injection ("ACI") project and the claim that this project will not increase particulate matter ("PM") emissions is flawed and incomplete and, in fact, PM-10 emissions are likely to exceed the PSD significance levels and trigger the requirement to obtain a prevention of significant deterioration ("PSD") permit and apply best available control technology ("BACT").

The Sierra Club has retained Dr. Ranajit (Ron) Sahu to evaluate Entergy's assertion that PM emissions will decrease following the addition of ACI to its operations at White Bluff. Dr. Sahu's Preliminary Report on this issue is attached as Exhibit 1, and his observations and conclusions are hereby incorporated into this comment letter.

Among other things, Dr. Sahu concludes that Entergy's technical support for its ACI project is fundamentally flawed in numerous ways, and is based on unreliable and insufficient technical information and documentation. Dr. Sahu asserts that without much more reliable and comprehensive technical support for this project, ADEQ cannot reasonable accept Entergy's assertion that PM emissions will decrease as a result of the addition of ACI. On the contrary, Dr. Sahu concludes that the filterable PM from the proposed ACI project will likely cause a collective increase of filterable PM of approximately 22.8 tons per year (from both increased particulate loading into the electrostatic precipitators ("ESPs") and increased road dust PM), which is sufficient to trigger PSD applicability and the requirement to apply BACT. On this basis alone, Dr. Sahu claims that the Draft White Bluff Permit cannot lawfully be issued.

Dr. Sahu makes the following statements in his preliminary report:

> What is clear is that with ACI addition, the particulate loading into the ESPs will increase. The Road Emission Calculations spreadsheet provided by Entergy states that the maximum annual ACI Injection Rate (or usage) will be 2,278 tons/year for both units. Assuming an ESP filterable PM efficiency of 99% (which is generous, given the total lack of information on ESP design, condition, and operating parameters) for each ESP, the incremental emissions of filterable PM as a result of the additional ACI loading is approximately 2,278*(1-0.99) = 22.8 tons/year. In addition, as Entergy notes, there are additional increases in fugitive PM emissions as a result of road traffic, ash hauling, ACI transport, etc. Collectively, the expected increase in filterable PM emissions, therefore, is likely above 22.8 tons/year. This exceeds the PSD Significant Emissions Rate for PM_{10}, which is 15 tons/year.1 [40 C.F.R. § 52.21(b)(23)(i). Thus, it is more likely than not that the addition of ACI, as proposed by Entergy for White Bluff Units 1 and 2, will trigger PSD review for this pollutant. This means that the application and permit are incomplete, since Entergy has not provided a BACT analysis, or any ambient air quality modeling analysis, or any of the other PSD application requirements (such as impacts to Air Quality Related Values), etc.

Id. at 5.

Based on Dr. Sahu's assessment, Sierra Club contends that there is no basis for ADEQ to accept Entergy's assertion that PM emissions will decrease. Sierra Club claims that the addition of ACI will likely increase PM emissions at White Bluff sufficient to trigger PSD review for this pollutant. For these and all the reasons discussed in Dr. Sahu's preliminary report, Sierra Club asserts that the Draft White Bluff Permit cannot lawfully be issued.

Response to Comment

ADEQ takes issue with the speculative nature of this comment. The commenter provides no definitive information to refute Entergy's analysis. The Entergy analysis studied the effect of ACI on emissions based on trial testing of White Bluff Unit 2 and analysis of coal used at the facility. This testing provided quantifiable numerical data indicating a reduction in particulate emissions with ACI. The information provided by the commenter provides several hypothetical and speculative arguments peppered with phrases such as "is likely" and "more likely than not". The Department responds to specific issues raised in the comment as follows:

1. *Unspecified ESP design parameters are cited as potentially affecting ACI emissions.* This claim is misplaced and irrelevant since the analyses provided by Entergy are based on actual trial testing of ACI and not an analysis of ESP design parameters.

2. *Changes in capacity or ACI injection during the trial testing may affect emission rates*. This statement is speculative at best. Moreover, it is not relevant since the analyses provided by Entergy were based on the difference in emission rates with and without ACI, not any total emission rate.

3. *ACI emissions are above 22 tpy based on usage and ESP efficiency*. The commenter incorrectly applied ESP efficiency to bulk activated carbon. It is not possible to estimate an emission rate in this manner. ESP efficiencies are related to particle size and the commenter made no attempt to estimate the ESP collection efficiency for ACI.

4. *Road emissions will likely cause emissions subject to PSD*. These increases in road emissions are neither quantified or specified by the commenter.

Comment #2

The draft White Bluff permit cannot lawfully be issued because no adequate demonstration has been performed, and ADEQ has no reasonable basis for concluding, that the White Bluff plant and the proposed changes to be made thereto will not result in interference with attainment of the NAAQS.

As addressed above, the proposed ACI project covered by the draft White Bluff permit is likely to result in an increase in PM emissions that is sufficient to trigger PSD applicability. Nearby Pulaski County, Arkansas is currently on the brink of exceeding the new annual $PM_{2.5}$ National Ambient Air Quality Standard ("NAAQS") primary standards and may well be designated as non-attainment for that standard in 2014. See 12/5/13 Letter from Gov. Mike Beebe to EPA regarding NAAQS designations. In light of surrounding ambient air quality, ADEQ must ensure that any modified permits for major sources of particulate matter do not interfere with attainment of the NAAQS.

In addition, SO_2 modeling that Sierra Club has performed has revealed that the White Bluff plant's allowable and actual SO_2 emissions are causing violations of the 1- hour average NAAQS for SO_2. *See* AERMOD Modeling of SO_2 Impacts of the Entergy White Bluff Coal Plant, prepared for Sierra Club by Khanh T. Tran, AMI Environmental, September 28, 201 1, at 6
(Table 2) (Ex. 2). Despite these facts, neither ADEQ nor anyone else has performed any air modeling analysis or other comparable demonstration to show that the White Bluff Plant and the proposed modification projects covered by the draft White Bluff Permit will not interfere with attainment of the NAAQS or otherwise cause air pollution that is harmful to human health. For this reason, the draft White Bluff Permit cannot be lawfully issued.

There are many provisions in state law, the Clean Air Act, and the Arkansas SIP that require air modeling in this situation or at least some substantive demonstration that NAAQS attainment will not be interfered with and that injurious air pollution will not result as a consequence of this permit. *See* APCEC Reg. 18.302; APCEC Reg. 19.402; APCEC Reg. 19.502; APCEC Reg. 26; Clean Air Act Section 110(a)(2)(C); 40 C.F.R. § 51.160-51.164.

Sierra Club understands that in April 2013, the Arkansas Legislature and governor enacted a new law, Act 1302, that prohibits ADEQ from requiring a permit applicant to submit air quality modeling to demonstrate compliance with the NAAQS, and prohibits ADEQ from undertaking its own modeling or even considering modeling submitted by a third-party without the applicant's consent. This law does contain exceptions for new source applications and sources subject to PSD review. Sierra Club's understanding is that ADEQ's previous practice of conducting air quality modeling for Title V permit renewals was integral to ADEQ's strategy for assuring compliance with the NAAQS. Indeed, Act 1302 now requires ADEQ to develop "NAAQS state implementation plans," presumably to fill the gap left in Arkansas's plan for assuring compliance with the NAAQS once ADEQ is no longer permitted to follow its previous practices. EPA has also expressed concern about the implications of Act 1302 for Arkansas's legal authority to ensure attainment of the NAAQS.

In its Statement of Basis for this permit, ADEQ explains that pursuant to Act 1302, no air dispersion modeling was performed, and that "criteria pollutants were not evaluated for impacts on the NAAQS." (Statement of Basis at p. 3). Combined with the flawed PSD applicability analysis submitted by Entergy, ADEQ has not satisfied state law and SIP requirements to ensure that the NAAQS are attained and that public health is protected. This deficiency must be corrected, and ADEQ must issue a revised draft permit for public review.

Response to Comment

The Department disagrees with the comment. The permit decision does change the previously issued and effective p ermit. However, the changes involved in this action are not a "modification" as that term is defined in Arkansas Pollution Control & Ecology Commission ("APC&EC") Regulation 19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable. Finally, the incorporation of the applicable MATS requirements does not impact SO_2 emissions at the White Bluff units. Therefore, the comments regarding modeling of SO_2 emissions are outside the scope of the permitting action.

Comment #3

The draft White Bluff permit should not be issued due to a lack of enforceability and specificity concerning the identification and description of the proposed air pollution control equipment and applicable requirements.

Response to Comment

Specific Conditions #29 through #64 of the draft permit incorporate the applicable requirements of 40 CFR Part 63, Subpart UUUUU. These conditions list emission standards, compliance methods, recordkeeping, and reporting provisions of the subpart. Those conditions will become enforceable upon final action on the permit. The identification and description of the proposed pollution control project can be found on Page 5 of the draft permit. ADEQ disagrees with the commenter's statements that the permit is lacking in enforceability and specificity. No change to the draft permit will be made.

Comment #4

The draft White Bluff permit is unlawful and should not be issued because it unlawfully fails to include or unlawfully relaxes or revises federally enforceable SIP limitations on opacity applicable to White Bluff Units 1 and 2.

The complete comment can be found with the record, however, the commenter's major issues for opacity include:

1. General discussion on the importance of opacity limits, and the relationship between opacity and PM emissions;
2. A review of the Arkansas SIP's opacity regulations;
3. A review of the Federal opacity requirements found in 40 C.F.R. Part 60, Subpart D;
4. A review of the permit condition(s) that streamlined/merged the Arkansas SIP and Federal opacity requirements into a hybrid limit;
5. An argument that hybrid limit found in the permit is less stringent; and
6. An argument that the hybrid opacity condition(s) found in the permit are unlawfully allowing for startup/shutdown exemptions.

Response to Comment

Comments regarding the permittee's opacity limits are outside the scope of this action. This permitting action is limited to those portions regarding incorporation of the applicable MATS requirements.

Furthermore, the Commenter's argument is untimely raised. Specifically, the facility's first condition concerning opacity was initially incorporated into the White Bluff facility's 2005 Title V permit renewal, 263-AOP-R3. The Commenter failed to submit comments on the affected permit provisions at that time that related to opacity and is therefore precluded from raising the issue now.

Notwithstanding the fact that the comment is untimely raised, the permit contains the correct New Source Performance Standards (hereinafter "NSPS") and SIP opacity limits. The NSPS limit is contained in Specific Condition 3 and again in Specific Condition 6, "*Opacity shall not exceed 20 percent except for one six-minute period per hour of not more than 27 percent opacity*". The SIP limit is contained in Specific Condition 28, "*shall not exceed 20% opacity* *except that emissions greater than 20% opacity but not exceeding 60% opacity will be allowed for not more than six (6) minutes in the aggregate in any consecutive 60-minute period, provided such emissions will not be permitted more than three (3) times during any 24-hour period.* " but it is "*held in abeyance provided that opacity does not exceed 20% except that emissions greater than 20% opacity but not exceeding 27% opacity will be allowed for not more than one 6-minute period per hour, provided such emissions will not be permitted more than ten (10) times per day.*"

The alternative limit in Specific Condition 28 matches the NSPS except that emissions over 20% but less than 27% are limited to 10 times per day, whereas the NSPS has no such limit (theoretically 24 times per day, i.e. once every hour). Therefore the limit is in fact more stringent than the NSPS.

The alternative limit is different from the SIP limit. The upper limit is lower at 27% rather than 60% but the number of occurrences of emissions is 10 per day as opposed to 3 times per 24 hour period. This alternative is allowable under APC&EC Reg. 19.505 and first appeared in permit 0263-AOP-R3 issued on April 28, 2005.

Specific Condition 28 further outlines actions ADEQ may take if these limits are exceeded. These actions are in accordance with Chapter 6 Upset and Emergency Conditions of Regulation 19.

The permit will therefore remain as written.

Comment #5

Summary of Permit Activity - Page 5: The seventh sentence in the second paragraph of the summary of permit activity currently reads as follows:

> "However, Entergy claims no increase in filterable particulate matter as measured by EPA Reference Method 5 is expected."

Entergy provided documentation of the expected increase in ESP efficiency resulting from the proposed mercury controls with the original December 17, 2012 submission to ADEQ for this project. This documentation included EPA RM 5 results from an engineering evaluation of ACI at White Bluff which demonstrated lower emissions of filterable PM with ACI than without. This documentation also included fly ash resistivity data obtained from the Energy and Environmental Research Center at the University of North Dakota which documented that fly ash resistivity decreased after halide treatment of the coal. Entergy expects that this decrease in fly ash resistivity will result in increased ESP collection efficiencies and will therefore result in a reduction in emissions of filterable PM.

To mitigate any risk of an increase in FPM emissions associated with ACI, Entergy plans to replace the traditional transformer/rectifier ("T/R") set in the first fields of each ESP at White Bluff with high-frequency power supplies ("HFPS") as part of the mercury controls project at each unit (SN-01 and SN-02), HFPS technology allows for a smooth and more stable output voltage compared to the voltage peaks and valleys which can occur with a conventional T/R set. This improvement in ESP field voltage stability is expected to result in additional decreases in filterable PM emissions from each unit.

Entergy requests that this sentence be rephrased as follows in the final permit.

> "However, Entergy anticipates no increase in filterable particulate matter as measured by EPA Reference Method 5."

Response to Comment

The requested language change has been made.

Comment #6

Emission Summary Table - Page 7: The total allowable emissions (lb/hr and tpy) appear to reflect the total permitted emissions from both the coal-fired and No. 2 fuel oil or biodiesel-fired operating scenarios for Unit 1 and Unit 2. As each of these scenarios is permitted for year-round operation, only the emissions from the higher-emitting scenario for each pollutant should be included in the plant-wide total allowable emissions value. This is consistent with the manner in which the total allowable emissions are presented in the current (R7) permit for the site. An example of these changes reflected in the format of the emission summary table is included in Attachment A to this letter. The totals included in Attachment A were calculated by summing the individual source emission limits, for each pollutant. For the HAP emission values, the total was rounded up to the nearest hundredth consistent with the formatting of the draft permit.

Response to Comment

The Emission Summary table has been updated.

Comment #7

Emission Summary Table - Page 11: The emission rates included in the summary table for SN-06C do not match the rates submitted for this source in the permit application, as supplemented via email on November 7, 2013. The total allowable emissions for SN-06C should be 129.9 lb/hr and 260.0 tpy PM, and 37.6 lb/hr and 90.1 tpy for PM_{10}. These values match the revised emission rate table (ERT) which was submitted for SN-06C during the application process.

Response to Comment

This comment should have also mentioned that there were two separate emails requesting to change the emission limits for SN-06C due to the change in the AP-42 equation for estimating road emissions. The first email was submitted on 11/7/2014. Specific Condition #74 was revised to match the provided ERT and calculations. ADEQ was unaware that the changes that had been made to update the limits in the Emission Summary Table were not preserved prior to the issuance of the draft. The second email was submitted on 12/10/2013 to correct a technical error with the calculations submitted on 11/7/2014. The overall result is a decrease in permitted limits. Both the Emission Summary Table and Specific Condition #74 limits have been corrected to reflect the information submitted and reviewed as part of the draft permitting decision.

Comment #8

Permit History - Page 15: Entergy notes that no summary of the R7 permit was added to the permit history section. ADEQ typically summarizes the changes from the previous permitting action with each subsequent permit issuance. A summary of the R7 permit action is requested to be added in keeping with this typical ADEQ practice.

Response to Comment

A summary of the changes made with the R7 permit has been included in the permit history.

Comment #9

Multiple Specific and Plantwide Conditions: A number of Specific Conditions and Plantwide Conditions in the draft permit contain a value of "Error! Reference Source not found" in place of a reference to General Provision 7. These error messages are requested to be replaced with references to General Provision 7 in the following conditions:

Specific Conditions: 4, 5, 12, 13, 17, 19, 27, 85, 92, 94, 98, 103, 110, 127 (first instance), 134, and 130, and Plantwide Condition: 16

Response to Comment

The noted error messages have been addressed to correctly reference GP7, where applicable.

Comment #10

Specific Condition 4 - Page 19: This condition establishes the compliance demonstration mechanism for the SO_2 limits of Specific Conditions 1 and 3. The compliance mechanism for the lb/hr limits of Specific Condition 1 is established as the arithmetic average of three one-hour periods of SO_2 emissions as measured by the CEMS and converted to pounds per hour per 40 CFR Part 75.

40 C.F.R. Part 75 establishes monitoring requirements for the acid rain mass emissions trading program. This program requires that substituted data be utilized to fill in any gaps in a facility's monitoring data. This substituted data represents an estimate of the emissions likely to have occurred from the unit during periods of missing and/or invalid CEMS data. When Part 75 monitoring data is used for the purposes of demonstrating compliance with a shorter-term emission limit, such as the lb/hr limits of Specific Condition #1, substituted data is not typically utilized. For example, see §60.334(b)(3)(iii) of NSPS Subpart GG. Similar examples exist in other NSPS subparts where EPA allows the use of Part 75 CEMS data for Part 60 compliance

purposes. ADEQ appears to have previously endorsed this position in Specific Conditions 12 and 13 which establish compliance demonstration requirements for SN-01 and SN-02 Operating Scenario II.

Entergy requests that the following sentence from Specific Condition 12 be added as the fourth sentence of Specific Condition 4.

> "Data Substituted in accordance with 40 CFR Part 75 for missing and/or invalid data will not be used for compliance with Specific Condition #1."

Response to Comment

The requested sentence has been added.

Comment #11

Specific Condition 5 - Page 19: For the same reasons outlined above, Entergy requests that the following sentence be added as the fourth sentence of Specific Condition 5.

> "Data substituted in accordance with 40 CFR Part 75 for missing and/or invalid data will not be used for compliance with Specific Condition #1."

Response to Comment

The requested sentence has been added.

Comment #12

Specific Condition 8 - Page 21: Entergy requests that the final sentence of this condition be revised to clarify that the quarterly excess emissions and monitoring system performance reports may be submitted to the Department via email. The ADEQ air enforcement branch currently accepts these reports electronically via email to airsubmission@adeq.state.ar.us, but the language in SC 8 is not clear that such electronic submission is acceptable. The final sentence of SC 8 is requested to be revised to read as follows:

> "Reports shall be submitted via email to airsubmission@adeq.state.ar.us or sent to the following address:"

Response to Comment

The requested change has been made.

Comment #13

Specific Condition 15 - Page 23: The final sentence of this condition should be revised to reference General Provision 17 consistent with the current (R7) permit for the facility.

Response to Comment

The requested change has been made.

Comment #14

Specific Conditions 24 and 25 - Page 24: The Plantwide Condition references in each of these conditions should be revised to reference Plantwide Condition 3 consistent with the current (R7) permit for the facility.

Response to Comment

The requested change has been made.

Comment #15

Specific Condition 28, Page 27: The cross-reference in the final sentence of Specific Condition 28 is requested to be revised to reference Specific Condition 7. This sentence referenced Specific Condition 7 in the R6 permit for the site and it appears that the Specific Condition 7 reference may have inadvertently been revised by ADEQ to a General Provision 7 reference in preparing the R7 permit. As Specific Condition 7 sets forth specific reporting requirements for opacity exceedances, this reference is appropriate. This change is consistent with the cross-reference in the equivalent language within the current Title V permit for Entergy's Independence Plant. See Specific Condition 3 of ADEQ permit 0449-AOP-R7.

Response to Comment

The requested change has been made.

Comment #16

Specific Condition 34(c)(iv) - Page 31: This condition was drafted by ADEQ as proposed by Entergy in the permit application. However, upon further review, Entergy requests that the phrase "... for an existing EGU..." be deleted from the final sentence of this condition for clarity. This language is unnecessary as both SN-01 and SN-02 are existing EGUs.

Response to Comment

The requested change has been made.

Comment #17

Specific Condition 50 - Page 38: The reference to Specific Condition #2 in this condition is requested to be updated to reference Specific Condition #30 which contains the applicability date for the MATS requirements.

Response to Comment

The requested change has been made.

Comment #18

Specific Condition 51 - Page 38: The reference to Specific Condition #2 in this condition is requested to be updated to reference Specific Condition #30 which contains the applicability date for the MATS requirements.

Response to Comment

The requested change has been made.

Comment #19

Specific Condition 53 - Page 38: This condition was drafted by ADEQ as proposed by Entergy in the permit application. However, upon further review this condition, while it arises from a different provision of Subpart UUUUU, is substantially duplicative of Specific Condition 43. To eliminate redundancy in the proposed conditions, Entergy requests that SC 53 be deleted and an additional regulatory reference to 40 CFR 63.10011(e) be added to SC 43.

Response to Comment

Specific Condition #53 was revised to RESERVED. The regulatory reference to 40 C.F.R. Part 63.10011(e) has been added to Specific Condition 43.

Comment #20

Specific Condition 55 - Page 39: This condition was drafted by ADEQ as proposed by Entergy in the permit application. However, upon further review this condition, while it arises from a different provision of Subpart UUUUU, is substantially duplicative of Specific Condition 42. To eliminate redundancy in the proposed conditions, Entergy requests that SC 55 be deleted and an additional regulatory reference to 40 CFR 63.10011(g) be added to SC 42.

Response to Comment

Specific Condition #55 was revised to RESERVED. The regulatory reference to 40 C.F.R. Part 63.10011(g) has been added to Specific Condition 42.

Comment #21

Specific Condition 74 Page 49: The PM emission limits for SN-06C are requested to be revised to 129.9 lb/hr and 260.0 tpy consistent with the emission rate table submitted to ADEQ for this source during the permit review process.

Response to Comment

The requested change has been made. See response to Comment #7.

Comment #22

18. Specific Condition 90 - Page 52: For clarity and consistency with the remainder of the condition, the definition of the term "TASH" is requested to be revised as follows:

> "TASH = monthly tons of fly ash disposed in the on-site landfill"

Response to Comment #

The requested change has been made.

Comment #23

19. Specific Condition 127 - Page 63: To correct the cross-reference error messages in the draft permit, the final sentence of this condition is requested to be revised to read as follows, consistent with the current (R7) permit for the site.

> "Construction of an alternate haul road shall comply with Plantwide Conditions #1 and #2."

Response to Comment

The requested change has been made.

Comment #24

Plantwide Condition 17 - Page 75: This condition is requested to be deleted from the permit. The draft R8 permit has been issued by ADEQ in response to the permit application referenced by this condition. As such, Entergy has satisfied this condition and it is no longer necessary.

Response to Comment

The requested change has been made.

Comment #25

Statement of Basis - Section 10: The regulatory applicability table in this section is requested to be revised to note the applicability of 40 CFR Part 63 Subpart UUUUU to SN-01 and SN-02.

Response to Comment

The requested change has been made.

Comment #26

Statement of Basis - Section 12(a): The text of Section 12(a) of the Statement of Basis (SOB) is requested to be revised to read as follows, "As acknowledged by ADEQ in Section 8(b) of the SOB, Entergy received a determination from ADEQ on February 19, 2013 that no permit or pre-authorization was required for the construction associated with the proposed pollution control project. As NAAQS review, when required, is a function of preconstruction permitting programs stemming from Title I of the Clean Air Act, and no such preconstruction permit approval was required for this project, no NAAQS review was required for this permitting action."

This permitting action did not involve the construction of any new emission units nor the modification of any existing emission units as that term is defined in Chapter 2 of ADEQ Regulation 19. As such, no NAAQS review was required.

Response to Comment

The permit decision does change the previously issued and effective permit. However, the changes involved in this action are not a "modification" as that term is defined at APC&EC Regulation 19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable. The section of the SOB has been changed to:

> This permit decision did not involve an emission increase over previously permitted rates; therefore a NAAQS evaluation is not required.

See Response to Comment #2.

Comment #27

The commenter submitted their comment to the email address provided in the public notice. The email reads as follows:

> *Allowing the coal-fired White Bluff power plant to increase its particle emissions is absolutely the WRONG thing to do! Think of all the increased health problems that this proposal would cause; that would not be in the best interests of people who live in the surrounding area of this plant. Please vote down this proposal!*
>
> *Chester A. Sautter*

Response to Comment

No specifics were provided with this comment. The commenter's opposition to the proposed modification has been noted.

The following written comments were received at the hearing held in Redfield, AR on August 14, 2014.

Comment #28 (Oral and Written)

Ms. Barbara Jarvis submitted the following written comments:

a. Economic implications: All fossil fuels are natural resources of the planet Earth. They are finite and exhaustible, unsustainable. Natural resources are capital, and we're spending them like [*TEXT ILLEGIBLE*]. This business is financially unsustainable.

b. Job security: coal jobs have declined. In [*TEXT ILLEGIBLE*] KY and VA employed 79,000 people; in 2012 they employed 41,000. The coal production remained steady, but the mining companies cut 38,000 jobs, replacing human beings with gigantic machines and technology. Coal jobs will continue to decline, but in 2013 the solar industry employed 142,698. 142,000 + compared to 89,000 jobs in coal.

c. "Clean Coal?" It will take 10-40% of the electricity produced by coal to "sequester" its carbon emissions will [*TEXT ILLEGIBLE*] 3,000 to 7,000 deaths, and millions in healthcare.

Response to Comment

The commenter's concerns have been noted. These comments, however, do not pertain to the permit modification. These comments do not request a change to the permit.

Comment #29 (Oral and Written)

Mr. Glenn Hooks is concerned about increased particulate matter and related health effects. The commenter references a Sierra Club analysis of the modification that estimated the proposed modification will result in an estimated 22 tons/yr of particulate matter emissions at the plant.

The commenter does not want the requested permit modifications approved unless ADEQ determines "either through modeling or otherwise" that the modification will not result in violation of any EPA air quality standard. The commenter mentioned that several provisions of Federal and Arkansas law require ADEQ to perform an air quality analysis before it approves a permit. The commenter understands that historically, ADEQ has used the Title V permitting process to assess a plant's emissions impact on EPA air quality, and with this permitting action ADEQ did not. The commenter states that ADEQ must develop another process for ensuring that the plant does not violate air quality standards.

The commenter concludes that the White Bluff plant is nearing the end of its useful lifecycle, and that it is time to consider replacing the plant with cleaner options as an alternative to spending the money in retrofits and upgrades.

Response to Comment

As to Mr. Hooks' comment regarding a NAAQS evaluation, the changes involved in this action are not a "modification" as that term is defined at APC&EC19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable.

The primary NAAQS are designed to protect human health. This permit contains limits and conditions that are protective of human health and the environment.

As to Mr. Hooks' comment regarding the useful life of the White Bluff plant, the commenter's concerns have been noted. However, the comment does not request a specific change to the permit.

See Response to Comment #2.

Comment #30

The draft White Bluff permit cannot lawfully be issued because no adequate determination has been made that the modified White Bluff plant will not violate a NAAQS.

Response to Comment

The permit decision does change the previously issued and effective permit. However, the changes involved in this action are not a "modification" as that term is defined at APC&EC Regulation 19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable.

See Response to Comment #2.

Comment #31

The draft White Bluff permit cannot lawfully be issued because the modified White Bluff plant will violate applicable requirements of Arkansas law that protect public health.

Response to Comment

This comment is vague and does not cite to any specific Arkansas regulation or statute. However, the primary NAAQS are designed to protect human health. This permit contains limits and conditions that are protective of human health and the environment. Additionally, the changes involved in this action are not a "modification" as that term is defined at APC&EC Regulation 19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable.

See Response to Comment #2.

Comment #32

Entergy's emissions estimates are unreliable and unverifiable.

The analysis Entergy performed to predict emissions from the modified White Bluff plant is almost entirely unreviewable and unverifiable because of a failure to provide necessary inputs and assumptions. As Dr. Sahu explains ADEQ has no basis to rely on Entergy's emissions estimates:

> In any analysis provided in a regulatory context, it is critically important that the entity performing the analysis provide all inputs and assumptions used so that the regulatory agency and others may assess the reliability and accuracy of the analysis. The New Source Review (NSR) analysis provided by Entergy to support the ACI project fails to meet this standard. Its work is almost entirely unreviewable and unverifiable because of a failure to provide support for the necessary inputs and assumptions or, in some cases, the inputs and assumptions themselves.

Supplement Report of Dr. Ranajit Sahu at 1 (Exhibit 1).

In his preliminary report that Sierra Club attached to its July 11, 2014 comments on the Draft White Bluff Permit, Dr. Sahu noted five critical flaws in Entergy's technical support for its claimed reduction in PM emissions from the ACI project:

- First, Entergy provides no details on the basic design parameters of the electrostatic precipitators ("ESPs") at White Bluff Units 1 and 2. This information is critical to any review regarding the performance of the ESPs with ACI addition at the White Bluff Plant. Sahu Preliminary Report at 1-2.6

- Second, Entergy does not state how much ACI (or which type) will be used in order to reduce mercury emissions to below the Mercury and Air Toxics Standards ("MATS") levels. In fact, no mercury testing data is provided at all. Thus, there is no data to show that a specific ACI process would lead to the necessary mercury reductions. Obviously, ACI runs that do not achieve the MATS-required mercury reductions are useless for assessing PM emissions since Entergy must comply with the MATS requirements for mercury. Sahu Preliminary Report at 2.

- Third, the June 2012 tests on Unit 1 are unreliable because the gas flow rates indicate that Unit 1 was running at a much reduced capacity during these tests thereby invalidating the tests' usefulness to predict emissions at full capacity. In addition, Unit 2 operates at much higher heat input rates than Unit 1 and thus Entergy's attempt to extrapolate results from Unit 1 to Unit 2 is not reasonable. Sahu Preliminary Report at 2

- Fourth, Entergy's failure to reasonably determine baseline PM emissions undermines its prediction of an emissions decrease. The identified wide range of possible PM baselines indicates that PM emission could increase, even under Entergy's flawed analysis. Sahu Preliminary Report at 3.

- Fifth, the Energy & Environmental Research Center tests provided by Entergy are not reliable because they were performed at an entirely different ESP, with different design parameters, and with no showing that these results could be achieved at the White Bluff ESPs. Sahu Preliminary Report at 3-6.

In his supplemental report attached to these comments, Dr. Sahu notes two additional flaws in Entergy's analysis:

- First, Entergy has not provided the inputs and assumptions used in the Aurora model that the company used to estimate projected futures estimates of emissions of all relevant pollutants. Entergy used this model to create projected heat input figures for Units 1 and 2. These heat input figures were then used by Entergy for all of its future emissions calculations. Without the inputs and assumptions used to generate the heat input figures, the emissions calculations themselves are not verifiable or even understandable. Sahu Supplemental Report at 1.

- Second, for a given future year, Entergy has adjusted (by roughly 5%) the Aurora projected heat input estimate to account for a "discrepancy" between how Entergy reports heat input to the U.S. EPA Clean Air Markets Division versus what Entergy believes the "accurate" heat input figure should be. In any case, in order to make this adjustment, Entergy states that it derived purportedly more accurate heat input numbers from fuel usage at each White Bluff unit and the heating value of the fuel(s). But Entergy provides only its final heat input values without any data to support the fuel usage and heating value inputs. Nor does Entergy provide any discussion as to why the heat input calculated from these parameters would be more accurate than the figures reported to the U.S. EPA. Sahu Preliminary Report at 1-2.

For all of these reasons, ADEQ has no reasonable basis for which to rely on Entergy's emissions estimates. There is therefore no demonstration in the permitting record that the modified White Bluff Plant will not violate federal or Arkansas air quality requirements. Without such an analysis, ADEQ cannot lawfully issue the modified White Bluff permit.

Response to Comment

No changes to the permit have been made.

PSD regulations allow a source to compare "baseline actual emissions" with "projected actual emissions". Entergy submitted emission projections showing that the project will not result in a significant emissions increase for any pollutant using the methods described in PSD regulations for calculating whether there is significant emissions increase.

The following oral comments were received at the hearing held in Redfield, AR on August 14, 2014.

Comment #33 (Oral)

Tony Mendoza with Sierra Club submitted written comments at the public hearing. He made two additional points via oral comments. Those comments were:

1. Mr. Mendoza understands that ADEQ hands are tied regarding the air quality modeling and Act 1302. He appreciates the other modeling ADEQ is doing in another process to ensure that air quality is protected for all citizens in Arkansas.

2. He urged the Department to consider the findings of Dr. Sahu's report regarding the increase in particulate matter from the ACI project.

Response to Comments

The first item raises no issue that requires a response. As to the second item, see Response to Comment #1.

Comment #34 (Oral)

The commenter stated that Pulaski County is already skirting the EPA regulations regarding PM and the proposed modification may well increase the PM load in Pulaski County and result in non-compliance with EPA standards. The commenter then reminded everyone that coal-fired power plants make cheap electricity but also increases pollution. The commenter stated that PM_{10} dangerous to people with lung conditions and their life span is shortened every time pollution is increased. The commenter then posed the question, "Is it right that we take away their life to have comfortable electricity for ourselves?"

Response to Comment

The commenter's concerns have been noted. However, the comment does not request a specific change to the permit.

As to the issue of PM, the addition of ACI is not anticipated to increase any emissions from the boilers. There may be a small increase in actual (versus permitted) road emissions from delivery of ACI but the cumulative impact on Pulaski County Attainment status will be trivial. Based on Entergy's analysis, overall emissions of PM will decrease.

Comment #35 (Oral)

The commenter was concerned about the fine PM. The commenter understood that Pulaski County is close to exceeding the EPA standards for safe levels for PM and that according to Sierra Club's report, the Entergy permit modification project could cause the PM standard to be exceeded. The commenter states that PSD could have an impact on Pulaski County and urged consideration of that. The commenter was concerned that Entergy is self-policing in determining the impacts from the modification. According to the commenter, that is very dangerous, and the very reason why ADEQ and EPA exist is so that companies do not self-regulate. The commenter requested that the Department consider all information available and not just what Entergy may be saying for their own vested interest. The commenter then states that federal and state law require that ADEQ perform an Air Quality analysis before approving a permit and asked, "Is Act 1302 in violation of those existing laws?"

Response to Comment

The comment raises several distinct issues. The Department's responses to those issues are as follows:

- The addition of ACI is not anticipated to increase any emissions from the boilers. Any increase in road emissions from delivery of ACI will have a trivial impact on Pulaski County Attainment status.

- The permit contains necessary compliance mechanisms. No specific issues were identified by the commenter regarding this issue.

- As to the issue of conducting at air quality analysis, the changes involved in this action are not a "modification" as that term is defined at APC&EC Regulation 19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable.

Comment #36 (Oral)

The commenter makes a number of statements that are generally for the continued use of coal.

Response to Comment

None of these statements directly refer to the proposed permit modifications at hand.

Comment #37 (Oral)

The commenter makes a number of statements in support of Entergy.

Response to Comment

None of these statements directly refer to the proposed permit modifications at hand.

Comment #38 (Oral)

The commenter makes statements supporting replacement of coal with renewable sources. The commenter understands that mercury causes health effects. The commenter is against ADEQ approving this modification with particulate emissions remaining the same or increasing. The commenter does not believe there is evidence the modification will be effective.

Response to Comment

The use of coal as a fuel source versus the use of renewables as a fuel source for the White Bluff plant is not an issue relevant to this permit modification. No specifics are presented by the commenter in the other issues presented.

Comment #39 (Oral and Written)

Ms. Shelley Buonaiuto submitted the following written comment:

The proposed modifications to the White Bluff Coal Plant to reduce mercury and some other toxic emissions are determined by a study by the Sierra Club to actually cause the increase of some fine PM by some 22 tons.

Pulaski County is close to exceeding EPA standards for safe levels of PM, so this extra could cause significant increase in cases of asthma and other respiratory illnesses, and heart disease.

ADEQ must conduct an independent air quality analysis before any permit for the proposed modification to White Bluff is approved.

Even if proper scrubbers could be added, those wouldn't prevent CO_2 emissions. The only thing I know of that is studied that could possibly contain CO_2 is carbon sequestration, which technology is not yet proven to be possible, efficient, safe, or financially viable.

Since White Bluff is already so old, dirty and close to retirement, it would make more sense to close the plant. This would make it easier to meet the proposed EPA regulation according to section 111d of the Clean Air Act, to reduce CO_2 emissions in AR by 44%.

Rather than spending money on a plant so close to retirement, money should be spent to provide transmission lines for the Integra natural gas plant, so it could operate at capacity.

The EPA regulations are already possibly too little, too late. There are methane releases from the Arctic Ocean 10 times the usual amount. In Siberia, huge holes are suddenly appearing. They've been flying helicopters down them theorized to be sudden releases of methane from under thawing permafrost. The Planet's climate is threatened by a feedback loop that would cause irreversible (at least within the next few hundred to a thousand years) accumulation of GHGs in the atmosphere causing heat to rise more than the 2% C decreed by NASA. Oceans would rise from 4-12 or more feet, inundating our coasts and islands, not to mention the other extreme weather events due to climate change.

Yes regulations will cause utility prices to rise. This could be remedied by the enactment of a state or national, or both, carbon fee and dividend, with 100% of the fee collect returned to the consumer. This would cushion the economy from negative impacts. It would also provide reliable price points for investment in renewables.

But for now what is immediately needed is an independent air quality analysis, performed by the ADEQ, before any ill advised permit is approved. The ADEQ is already involved in a law suit due to the permit granted to the Cargill and C&H Hog farm without the necessary analysis of impacts on the Buffalo River, or proper notification of those affected. We need to ADEQ to protect our air and water quality and our health. You are the government agency we depend on for this.

The commenter did not know about Act 1302 prior to the public meeting understands ADEQ has to comply with Act 1302. There must be some kind of mechanism that allows ADEQ to conduct an independent air quality analysis before any permit for the proposed modifications is approved. Entergy's analysis should not be trusted.

Response to Comment

The commenter raises multiple issues. The Department's responses to those issues are as follows:

The addition of ACI is not anticipated to increase any emissions from the boilers. Any increase in road emissions from delivery of ACI will have a trivial impact on Pulaski County Attainment status.

- The comments on CO_2 and its impact on the environment are noted. However, CO_2 is not at issue in this permit modification.

- Alternatives to this facility (such as the Union Power- Entegra natural gas combined cycle plant) are not at issue in this permit modification.

- As to the issue of conducting an air quality analysis, the changes involved in this action are not a "modification" as that term is defined at APC&EC Regulation 19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable.

Comment #40 (Oral)

The commenter makes a number of statements in support of Entergy. The commenter first contends that the MATS control system being installed will allow the plant to be compliant with state and federal regulations. The commenter supports the permit request. The commenter has not had any health effects related to the air quality around the facility. The commenter is against closing the plant and displacing hundreds of people from their jobs.

Response to Comment

The commenter's support for Entergy is noted.

Comment #41 (Oral)

The commenter does not want to take the risk of exceeding safe levels of PM (particulate matter) and supports transitioning to clean power. The commenter supports solar energy. According to the commenter, there are laws that require ADEQ to perform air quality analysis before approving a permit and consider alternatives.

Response to Comment

The use of solar energy as fuel source is not an issue relevant to this permit modification. As to the issue of conducting an air quality analysis, the changes involved in this action are not a "modification" as that term is defined at APC&EC Regulation 19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable.

ADEQ
OPERATING
AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation 26:

Permit No. : 0263-AOP-R8

IS ISSUED TO:

Entergy Arkansas, Inc. (White Bluff Plant)
1100 White Bluff Road
Redfield, AR 72132
Jefferson County
AFIN: 35-00110

THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

August 9, 2012 AND August 8, 2017

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Mike Bates

JAN 2 2 2015

Mike Bates
Chief, Air Division

Date

Table of Contents

List of Acronyms and Abbreviations

A.C.A.	Arkansas Code Annotated
AFIN	ADEQ Facility Identification Number
CFR	Code of Federal Regulations
CO	Carbon Monoxide
HAP	Hazardous Air Pollutant
lb/hr	Pound Per Hour
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO_x	Nitrogen Oxide
PM	Particulate Matter
PM_{10}	Particulate Matter Smaller Than Ten Microns
SNAP	Significant New Alternatives Program (SNAP)
SO_2	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

SECTION I: FACILITY INFORMATION

PERMITTEE:	Entergy Arkansas, Inc. (White Bluff Plant)
AFIN:	35-00110
PERMIT NUMBER:	0263-AOP-R8
FACILITY ADDRESS:	1100 White Bluff Road Redfield, AR 72132
MAILING ADDRESS:	1100 White Bluff Road Redfield, AR 72132
COUNTY:	Jefferson County
CONTACT NAME:	Barry Snow
CONTACT POSITION:	Senior Lead Environmental Specialist
TELEPHONE NUMBER:	501-688-7270
REVIEWING ENGINEER:	Charles Hurt, P.E.
UTM North South (Y):	Zone 15: 3809023.52 m
UTM East West (X):	Zone 15: 577562.11 m

SECTION II: INTRODUCTION

Summary of Permit Activity

Entergy Arkansas, Inc. - White Bluff located in Redfield, Arkansas is a two-unit electric generating station which generates electric energy for sale. Entergy submitted an application to incorporate the applicable requirements of 40 CFR Part 63, Subpart UUUUU – *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units,* also referred to as the Mercury Air Toxic Standards (MATS), and to account for the additional traffic on the roads due to deliveries of activated carbon and halide solution deliveries. Two activated carbon silos and two aqueous halide storage units were added to the insignificant activities list. Overall, permitted emission decreased by 77.5 tpy PM and 15.0 tpy PM_{10}.

Compliance with MATS will result in the installation of additional emissions controls on each of the Unit 1 and Unit 2. The primary emission control unit will be an activated carbon injection (ACI) system. The ACI system will use either brominated activated carbon or non-halogenated activated carbon that is injected post combustion. If non-brominated activated carbon is used by the ACI then a separate halide solution would be applied to the coal prior to combustion. That halide will not be chloride or fluoride. Entergy anticipates the ACI will introduce additional filterable particulate matter into the exhaust prior to each unit's electrostatic precipitator (ESP). However, Entergy anticipates no increase in filterable particulate matter as measured by EPA Reference Method 5.. The presence of bromine will decrease the resistivity of the fly ash and thereby increases the collection efficiency of the ESP. Entergy stated that the ACI system will not affect the heat rate or the dispatch of the units and will not alleviate outages or derates. No increase in particulate matter from operation of the ACI systems from either Unit 1 or Unit 2 was concluded.

Process Description

White Bluff Steam Electric Station operates currently as a base-load facility. The plant has two identical coal-fired units (Units 1 and 2) with a total capacity of approximately 1690 megawatts (MW). Sub-bituminous or bituminous coal is delivered by rail or barge. Each rail car is equipped with rotary couplings which enable the rotary car dumper (SN-03) to grasp one car at a time and empty it without removing the car from the train. The rotary car dumper is capable of emptying approximately 30 cars per hour. Transfer conveyors move the coal to a transfer tower. From here the coal can be conveyed to three different areas including the plant to be pulverized and burned, the stacker/reclaimer, or the storage area. The stacker reclaimer has the capability of either stacking coal out or reclaiming the coal from the storage area. The storage area is used for long term storage of coal and is also managed by the use of heavy vehicles including front end loaders and bull dozers.

Coal is burned in the steam generators (SN-01 and SN-02) which feed turbine generators to produce electricity. Exhaust gases from both units are expelled through two 1000 foot stacks within a common outer chimney shell. Waste heat dissipation is through two hyperbolic natural draft cooling towers (SN-17 and SN-18) which obtain makeup water from the Arkansas River and from the capture of site drainage. Other major plant components include facilities for storage and handling of coal and disposal of ash; a switch-yard; electrostatic precipitators; water treatment; surge and other ponds; and intake and discharge structures.

Regulations

The following table contains the regulations applicable to this permit.

Regulations
Arkansas Air Pollution Control Code, Regulation 18, effective June 18, 2010
Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective July 27, 2013
Regulations of the Arkansas Operating Air Permit Program, Regulation 26, effective November 18, 2012
40 CFR Part 60, Subpart D – *Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971*
40 CFR Part 61, Subpart M – *National Emissions Standard for Asbestos*
40 CFR Part 72, Subpart A-D – Permits Regulation (Acid Rain)
40 CFR Part 73, Subpart B – Sulfur Dioxide Allowance System
40 CFR Part 75 – Continuous Emission Monitoring
40 CFR Part 76 – Acid Rain Nitrogen Oxide Emission Reduction Program
40 CFR Part 77 – Excess Emissions
40 CFR Part 64 – Compliance Assurance Monitoring
40 CFR Part 82 – Protection of Stratospheric Ozone
40 CFR Part 63, Subpart ZZZZ - *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*
40 CFR Part 60, Subpart IIII - *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*
40 CFR Part 63, Subpart UUUUU – *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units* (MATS)

This facility is a major source of greenhouse gases.

Emission Summary

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
	Total Allowable Emissions	PM	1,584.1	6,607.0
		PM_{10}	1,483.5	6,414.8
		SO_2	20,990.1	91,920.7
		VOC	100.6	327.6
		CO	6,508.8	28,482.4
		NO_X	12,240.2	53,520.4
		Lead	0.70	2.10
	HAPs	2,3,7,8-TCDD	1.54E-08	6.58E-08
		2-Chloroacetophenone	0.01	0.03
		Acetaldehyde	0.62	2.62
		Acrolein	0.31	1.33
		Arsenic	0.44	1.89
		Benzene	1.41	5.99
		Benzyl Chloride	0.76	3.22
		Beryllium	0.02	0.10
		Cadmium	0.06	0.24
		Carbon Disulfide	0.14	0.60
		Chloroform	0.06	0.27
		Chromium	0.28	1.20
		Chromium VI	0.09	0.36
		Cobalt	0.11	0.46
		Cyanide	2.70	11.50
		Dimethyl Sulfate	0.05	0.22
		Ethylene Dichloride	0.04	0.18
		Formaldehyde	0.77	3.36
		Hydrogen Chloride	1,296.00	5,520.00
		Hydrogen Fluoride	157.60	690.00
		Isophorone	0.63	2.67
		Manganese	0.53	2.26
		Mercury	0.09	0.38
		Methyl Chloride	0.57	2.44
		Methyl Hydrazine	0.18	0.78
		Nickel	0.30	1.29
		Phenol	0.02	0.07
		POM	0.06	0.23
		Propionaldehyde	0.41	1.75
		Selenium	1.41	5.99
	Air Contaminants **	Sulfuric Acid	27.15	118.92

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
01 (C1)	Unit 1 Boiler – Coal Fired	PM	714.0	3,127.4
		PM_{10}	714.0	3,127.4
		SO_2	10,440.0	45,727.2
		VOC	35.0	153.3
		CO	3,247.0	14,221.9
		NO_X	6,090.0	26,674.2
		Lead	0.30	1.00
		2,3,7,8-TCDD	7.72E-09	3.29E-08
		2-Chloroacetophenone	0.0038	0.0161
		Acetaldehyde	0.31	1.31
		Acrolein	0.1566	0.6670
		Arsenic	0.2214	0.9430
		Benzene	0.7020	2.9900
		Benzyl Chloride	0.3780	1.6100
		Beryllium	0.0113	0.0483
		Cadmium	0.0275	0.1173
		Carbon Disulfide	0.0702	0.2990
		Chloroform	0.0319	0.1357
		Chromium	0.1404	0.5980
		Chromium VI	0.0427	0.1817
		Cobalt	0.0540	0.2300
		Cyanide	1.35	5.75
		Dimethyl Sulfate	0.0259	0.1104
		Ethylene Dichloride	0.0216	0.0920
		Formaldehyde	0.1296	0.5520
		Hydrogen Chloride	648.00	2760.00
		Hydrogen Fluoride	78.80	345.00
		Isophorone	0.31	1.33
		Manganese	0.26	1.13
		Mercury	0.04	0.19
		Methyl Chloride	0.29	1.22
		Methyl Hydrazine	0.0918	0.3910
		Nickel	0.1512	0.6440
		Phenol	0.0086	0.0368
		POM	0.03	0.10
		Propionaldehyde	0.21	0.87
		Selenium	0.70	2.99
		Sulfuric Acid	12.77	55.93
01 (C1)	Unit 1 Boiler – No. 2 Fuel Oil or Bio-diesel	PM	24.1	105.5
		PM_{10}	24.1	105.5
		SO_2	573.0	2,509.7
		VOC	1.9	8.1
		CO	36.5	159.9
		NO_X	175.2	767.3
		Lead	0.10	0.10
		Arsenic	0.0040	0.0175
		Benzene	0.0016	0.0068

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
01 (C1)	Unit 1 Boiler – No. 2 Fuel Oil or Bio-diesel	Beryllium	0.0030	0.0131
		Cadmium	0.0030	0.0131
		Chromium	0.0030	0.0131
		Formaldehyde	0.35	1.53
		Manganese	0.0060	0.0263
		Mercury	0.0030	0.0131
		Nickel	0.0030	0.0131
		POM	0.02	0.11
		Selenium	0.0150	0.0657
		Sulfuric Acid	8.78	38.44
02 (C2)	Unit 2 Boiler – Coal Fired	PM	714.0	3,127.4
		PM_{10}	714.0	3,127.4
		SO_2	10,440.0	45,727.2
		VOC	35.0	153.3
		CO	3,247.0	14,221.9
		NO_X	6,090.0	26,674.2
		Lead	0.30	1.00
		2,3,7,8-TCDD	7.72E-09	3.29E-08
		2-Chloroacetophenone	0.0038	0.0161
		Acetaldehyde	0.31	1.31
		Acrolein	0.1566	0.6670
		Arsenic	0.2214	0.9430
		Benzene	0.7020	2.9900
		Benzyl Chloride	0.3780	1.6100
		Beryllium	0.0113	0.0483
		Cadmium	0.0275	0.1173
		Carbon Disulfide	0.0702	0.2990
		Chloroform	0.0319	0.1357
		Chromium	0.1404	0.5980
		Chromium VI	0.0427	0.1817
		Cobalt	0.0540	0.2300
		Cyanide	1.35	5.75
		Dimethyl Sulfate	0.0259	0.1104
		Ethylene Dichloride	0.0216	0.0920
		Formaldehyde	0.1296	0.5520
		Hydrogen Chloride	648.00	2760.00
		Hydrogen Fluoride	78.80	345.00
		Isophorone	0.31	1.33
		Manganese	0.26	1.13
		Mercury	0.04	0.19
		Methyl Chloride	0.29	1.22
		Methyl Hydrazine	0.0918	0.3910
		Nickel	0.1512	0.6440
		Phenol	0.0086	0.0368
		POM	0.03	0.10
		Propionaldehyde	0.21	0.87
		Selenium	0.70	2.99
		Sulfuric Acid	12.77	55.93

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
02 (C2)	Unit 2 Boiler – No. 2 Fuel Oil or Bio-diesel	PM	24.1	105.5
		PM_{10}	24.1	105.5
		SO_2	573.0	2,509.7
		VOC	1.9	8.1
		CO	36.5	159.9
		NO_X	175.2	767.3
		Lead	0.10	0.10
		Arsenic	0.0040	0.0175
		Benzene	0.0016	0.0068
		Beryllium	0.0030	0.0131
		Cadmium	0.0030	0.0131
		Chromium	0.0030	0.0131
		Formaldehyde	0.35	1.53
		Manganese	0.0060	0.0263
		Mercury	0.0030	0.0131
		Nickel	0.0030	0.0131
		POM	0.02	0.11
		Selenium	0.0150	0.0657
		Sulfuric Acid	8.78	38.44
05 (C3)	Auxiliary Boiler	PM	4.5	19.4
		PM_{10}	4.5	19.4
		SO_2	105.2	460.8
		VOC	0.4	1.5
		CO	6.7	29.4
		NO_X	32.2	140.9
		Lead	0.10	0.10
		Arsenic	0.0007	0.0032
		Benzene	0.0003	0.0013
		Beryllium	0.0001	0.0002
		Cadmium	0.0006	0.0024
		Chromium	0.0006	0.0024
		Formaldehyde	0.06	0.28
		Manganese	0.0011	0.0048
		Mercury	0.0006	0.0024
		Nickel	0.0006	0.0024
		POM	0.0044	0.0194
		Selenium	0.0028	0.0121
		Sulfuric Acid	1.61	7.06
3	Rail Car Rotary Dumper	PM	0.1	0.1
		PM_{10}	0.1	0.1
		VOC	1.3	2.2‡

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
06A	Handling/ Conveying Emissions	PM PM_{10} VOC	0.8 0.4 0.2	3.4 1.6 2.2‡
06B	Stacker/ Reclaimer Emissions	PM PM_{10}	1.0 0.5	4.3 2.0
06C	Storage Piles/Haul Road Emissions	PM PM_{10}	129.9 37.6	260.0 90.1
4 (M30-M31)	Fly Ash Silo with Fabric Filters	PM PM_{10}	0.1 0.1	0.1 0.1
7	Fuel Oil Tank	VOC	1.9	2.4
14 (T25)	Miscellaneous Storage Tanks	VOC	0.1	0.1
15 (T26)	Miscellaneous Storage Tanks	VOC	0.1	0.1
16 (T32)	Miscellaneous Storage Tanks	VOC	18.9	0.1
17 (X24)	Cooling Tower	PM PM_{10}	4.6 4.6	19.9 19.9
18 (X25)	Cooling Tower	PM PM_{10}	4.6 4.6	19.9 19.9
19	Coal Barging and Transfer	PM PM_{10}	9.8 2.5	24.2 6.1
20	Degreasing Operations	VOC	6.8	13.6
21	Emergency Diesel Generator	PM PM_{10} SO_2 VOC CO NO_X Acetaldehyde Acrolein Benzene Formaldehyde	0.6 0.5 4.2 0.8 7.0 26.3 0.0002 0.0001 0.0064 0.0006	0.7 0.6 4.5 0.8 7.6 28.5 0.0002 0.0001 0.0069 0.0007

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
22	Emergency Diesel Fire Pump	PM	0.1	0.2
		PM_{10}	0.1	0.2
		SO_2	0.7	1.0
		VOC	0.1	0.2
		CO	1.1	1.6
		NO_X	1.7	2.6
		Acetaldehyde	0.0018	0.0028
		Acrolein	0.0002	0.0003
		Benzene	0.0022	0.0034
		Formaldehyde	0.0028	0.0042

*HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.
**Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.
‡ Combined annual VOC emission limit for SN-03 and SN-06A

SECTION III: PERMIT HISTORY

263-A was the first permit issued to the facility. 263-A permitted the installation of two coal-fired steam electric generating units served by a combined 1000 foot stack. The permit established the New Source Performance Standards limits for sulfur dioxide by usage of low sulfur coal.

263-AR-1 was issued to Arkansas Power & Light Company - White Bluff Steam Electric Station on April 9, 1991. After the issuance of permit 263-A, it was discovered that the particulate emission limitation was 0.027 lb/MMBtu heat input instead of the 40 CFR 60 Subpart D limit of 0.10 lb/MMBtu heat input. The more stringent limitation caused a problem with compliance with the operating permit. Due to the variability in the quality of coal, AP&L requested a revised particulate emission limit in order to maintain compliance with its operating permit. Air permit 263-AR-1 incorporated the new limits for particulate matter, identified source of pollution not previously addressed in the original permit, and estimated pollution emissions from fuel oil storage facilities and air toxic emissions.

263-AOP-R0 was the first operating air permit issued to Entergy-Arkansas, Inc. - White Bluff Steam Electric Station under Regulation 26. No physical changes in the method of operation at the facility occurred prompting this permit issuance.

> Entergy-Arkansas, Inc. proposed to increase the CO limit for the White Bluff facility from 300 lb/hr (50 ppm) to 3247.0 lb/hr or 300 ppm hourly (100 ppm 24-hour average) to reflect actual emissions indicated by stack testing. This increase in CO emissions was not subject to PSD review, because previous permit limits were based on AP-42 factors that were inaccurate for this facility. Also, the White Bluff Steam Electric Station began construction before the PSD regulations were promulgated. Modeling analysis at a 500 ppm emission rate was conducted and showed no significant impact to the *NAAQS*.
>
> Entergy-Arkansas, Inc. elected to take on a new NO_X emission limit of 0.45 lb/MMBtu annual average at White Bluff Units 1 and 2. This early election was allowed under 40 CFR 76 of the Acid Rain Regulations. The NSPS limit of 0.7 lb/MMBtu and the state-imposed lb/hr limit still apply to these units.

263-AOP-R1 was issued on May 30, 2000. The facility modified the Title V permit to allow for the receipt of coal via barge. Barges arrived at the plant on the Arkansas River. The coal was transferred from the barge to trucks through a series of conveyors and hoppers (SN-19). This modification also moved the following sources to the insignificant activities list: SN-08, SN-09, SN-10, SN-11, SN-12, and SN-13.

263-AOP-R2 was issued on December 20, 2002. This minor modification was necessary to replace the control equipment associated with the Rail Car Rotary Dumper (SN-03) and Handling/Conveying Emissions (SN-06) with non-hazardous dust suppressant chemical foam spraying stations. The volatile organic compound (VOC) emissions from the dust suppressant chemical foam spray were permitted at 17.7 tons per year. This permitting action also modified the visible emissions conditions for SN-06. In addition, the following sources no longer operate or never existed at the facility and were removed from the permit: Barge Unloading Operations (SN-19) and some of the Handling/Conveying Emissions (SN-06) M10 Emergency Stackout Pile, M12 Dead Storage Hopper 4A, M13 Dead Storage Hopper 3A, M14 Dead Storage Hopper 2A, and M33 Fly Ash Rail Car Loading Silo. The M15 Dead Storage Vault was removed from the permit as a source of emissions since it is completely enclosed, underground, and the rotoclone dust collector connected to it is inoperable. This rotoclone was removed or abandoned in place.

263-AOP-R3 was issued on April 28, 2005. In addition to renewing the facility's Title V air permit, this permitting action was necessary to permit emissions of hazardous air pollutants (HAPs); recalculate the permitted coal handling emission rates (SN-06); increase the throughput of SN-14 and SN-16; update the PM and PM_{10} emission rates (SN-01, SN-02, and SN-05) to include condensable particulate matter; update the insignificant activities list; add new stack testing requirements for PM, PM_{10}, and CO; permit the degreasers (SN-20) which were previously submitted as insignificant; correct the fly ash silos (SN-04) permitted PM emission rates; correct the facility name to Entergy Arkansas, Inc. from Entergy Services, Inc.; remove emission point M32 (SN-06A) since this emission point has been removed from service; increase the cooling tower circulating water flow rates (SN-17 and SN-18); and reduce the permitted VOC content of the chemical foam spray used at SN-03 and SN-06A. The total permitted emission rate increases due to this permitting action included: 1,01 3.6 tons per year (tpy) PM, 738.7 tpy PM_{10}, 39.2 tpy SO_2, and all hazardous air pollutant and air contaminant emission rates for this facility increased due to these pollutants previously not being permitted.

263-AOP-R4 was issued on April 26, 2006. Entergy Arkansas, Inc. - White Bluff located in Redfield, Arkansas is a two-unit electric generating station which generates electric energy for sale. This permitting action was necessary to:

1. Permit coal barging and transfer (SN-19);
2. Increase the permitted circulating water flow rate to 22,125 kgal/hr for the cooling towers (SN-17 and SN-18);
3. Reduce the permitted TDS (total dissolved solids) limit to 2,800 parts per million for the cooling towers (SN-17 and SN-18);
4. Remove the words "from northeastern Wyoming" from the process description;
5. Remove the "-88" from ASTM D4507-88 in Specific Condition # 29;
6. Add 40 CFR Part 63, Subpart DDDDD - *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters* as applicable to SN-05;
7. Allow for the use of bituminous coal;
8. Increase the coal sulfur and ash contents;
9. Set the PM_{10} emission rate limits equal to the PM emission rate limits for SN-01 and SN-02;
10. Revise Specific Condition # 25; and
11. Add Specific Condition # 26.

The total annual permitted emission rate increases due to this permitting action include: 2,311.3 tons per year (tpy) PM and 5,034.8 tpy PM_{10}. These increases do not require PSD review because there is no physical modification to the boilers (SN-01 and SN-02) and the coal barging and transfer (SN-19) has been permitted below the PSD trigger.

0263-AOP-R5 was issued on August 24, 2007. With the modification, Entergy requested to remove the requirement to use dust suppressant foam at SN-06A. Entergy completed a project improving the conveyor enclosure seals, installed new seals, and added a dust collector. This dust collector or "Bin-vent" is vented inside the building. Entergy also submitted the language changes necessary to incorporate bio-diesel into the permit as fuel for SN-01 or SN-02. Entergy also submitted the necessary calculations to incorporate their sulfuric acid (H_2SO_4) emissions from SN-01 and SN-02. Additionally, Entergy determined that Scenario 2 – Fuel Oil Firing, PM/PM_{10} emissions from SN-01 and SN-02 is more accurate when the control efficiency for the ESP is removed since the ESP is not in operation during startup when fuel oil is being used. Revised emissions reflecting this determination were submitted. The total annual permitted emission rate increases due to this permitting action include: 12.3 tons per year PM, 12.7 tpy PM_{10}, and 178.52 tpy H_2SO_4. Additionally, on July 30, 2007, the District of Columbia Court of Appeal vacated the National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT). Due to the Boiler MACT rules being vacated, the permit was updated by removing all conditions and wording related to the Boiler MACT.

0263-AOP-R6 was issued on January 12, 2009. Entergy was authorized to install a new dust suppression system at the bottom of 2A conveyor (SN-06A), and revised the fuel oil N_2O emissions based on updated emission factors. The N_2O annual emissions for the fuel oil fired scenario increased by 10.48 tpy. The facility total annual permitted emission rates increase was 0.88 tpy N_2O.

0263-AOP-R7 was issued on August 9, 2012. The Title V permit was renewed with modifications. The changes included adding a replacement fire pump, moving an emergency generator from the Insignificant Activity list to a permitted source, increased solvent use (SN-20) to 4000 gallons per year, added H_2SO_4 (sulfuric acid) emission estimates to auxiliary boiler emission rates, revised the oil fired scenario, and added a portable diesel tank (T127) to the insignificant activity list. Permitted emissions of particulate matter decreased due to coal handling emission calculation updates. Other pollutant emission rates changed in minor amounts due to updated calculations. Permitted emissions changed by -285.5 tpy PM, -108.5 tpy PM_{10}, 6.9 tpy SO_2, 9.2 tpy CO, 31.5 tpy NOx, -59.7 tpy H_2SO_4, 1.2 tpy HCl and less than 1 tpy change in all other HAP emission rates combined.

SECTION IV: SPECIFIC CONDITIONS

SN-01, SN-02, & SN-05
Boilers

Source Description

SN-01 and SN-02 are 8700 million BTU per hour coal fired boilers. The boilers use sub-bituminous or bituminous coal as their primary fuel and No. 2 fuel oil or bio-diesel as the start-up fuel at a maximum rate of 1000 MMBtu/hr. The boilers are permitted to operate under alternating scenarios. Scenario I represents combustion from coal and Scenario II represents No. 2 fuel oil or bio-diesel combustion. At times when coal and oil are fired together, and for one hour after switching from scenario I to Scenario II, the limits of Scenario I apply. The boilers supply steam which feed turbine generators to produce electricity. Both units are subject to NSPS Subpart D, which regulates emissions of particulate matter, sulfur dioxide and nitrogen oxides from fossil fuel-fired steam generators.

Particulate emissions from these two units are controlled with electrostatic precipitators. NSPS emissions standards for particulate matter are 0.1 lb/MMBtu and a maximum opacity of 20 percent. A continuous opacity monitor records emissions opacity.

Sulfur dioxide emissions from SN-01 and SN-02 are limited by the use of low-sulfur coal. The NSPS emission standard for sulfur dioxide is 1.2 lb/MMBtu. A continuous emissions monitor measures sulfur dioxide emissions.

SN-05 is a 183 million BTU per hour boiler. This auxiliary boiler combusts No. 2 fuel oil or bio-diesel in order to provide steam for unit start-up activities. There are no control devices associated with this source.

Specific Conditions

1. The permittee shall not exceed the emission rates, when operating under Scenario I: coal firing, coal and oil firing and the first hour when switching form Scenario I to Scenario II, set forth in the following table. [Regulation 19, §19.501 et seq., and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
SN-01 (C1)	Unit 1 Boiler - Coal Fired	PM_{10}	714.0	3,127.4
		SO_2	10,440.0	45,727.2
		VOC	35.0	153.3
		CO	3,247.0	14,221.9
		NO_x	6,090.0	26,674.2
		Lead	0.3	1.0

SN	Description	Pollutant	lb/hr	tpy
SN-02 (C2)	Unit 2 Boiler – Coal Fired	PM_{10}	714	3,127.4
		SO_2	10,440.0	45,727.2
		VOC	35.0	153.3
		CO	3,247.0	14,221.9
		NO_x	6,090.0	26,674.2
		Lead	0.3	1.0

2. The permittee shall not exceed the emission rates, when operating under Scenario I: coal firing, coal and oil firing and the first hour when switching form Scenario I to Scenario II, set forth in the following table. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
SN-01 (C1)	Unit 1 Boiler – Coal Fired	PM	714.0	3,127.4
		Acetaldehyde	0.3078	1.311
		Acrolein	0.1566	0.667
		Arsenic	0.2214	0.943
		Benzene	0.702	2.99
		Benzyl Chloride	0.378	1.61
		Beryllium	0.01134	0.0483
		Cadmium	0.02754	0.1173
		Carbon Disulfide	0.0702	0.299
		2-Chloroacetophenone	0.00378	0.0161
		Chloroform	0.03186	0.1357
		Chromium	0.1404	0.598
		Chromium VI	0.04266	0.1817
		Cobalt	0.054	0.23
		Cyanide	1.35	5.75
		Dimethyl Sulfate	0.02592	0.1104
		Ethylene Dichloride	0.0216	0.092
		Formaldehyde	0.1296	0.552
		Hydrogen Chloride	648.0	2760.0
		Hydrogen Fluoride	78.8	345.0
		Isophorone	0.3132	1.334
		Manganese	0.2646	1.127
		Mercury	0.04482	0.1909
		Methyl Chloride	0.2862	1.219
		Methyl Hydrazine	0.0918	0.391
		Nickel	0.1512	0.644
		Phenol	0.00864	0.0368
		POM	0.03	0.10
		Propionaldehyde	0.2052	0.874

SN	Description	Pollutant	lb/hr	tpy
		Selenium	0.702	2.99
		Sulfuric Acid	12.77	55.93
		2,3,7,8-TCDD	7.722E-09	3.29E-08
SN-02 (C2)	Unit 2 Boiler – Coal Fired	PM	714.0	3,127.4
		Acetaldehyde	0.3078	1.311
		Acrolein	0.1566	0.667
		Arsenic	0.2214	0.943
		Benzene	0.702	2.99
		Benzyl Chloride	0.378	1.61
		Beryllium	0.01134	0.0483
		Cadmium	0.02754	0.1173
		Carbon Disulfide	0.0702	0.299
		2-Chloroacetophenone	0.00378	0.0161
		Chloroform	0.03186	0.1357
		Chromium	0.1404	0.598
		Chromium VI	0.04266	0.1817
		Cobalt	0.054	0.23
		Cyanide	1.35	5.75
		Dimethyl Sulfate	0.02592	0.1104
		Ethylene Dichloride	0.0216	0.092
		Formaldehyde	0.1296	0.552
		Hydrogen Chloride	648.0	2760.0
		Hydrogen Fluoride	78.8	345.0
		Isophorone	0.3132	1.334
		Manganese	0.2646	1.127
		Mercury	0.04482	0.1909
		Methyl Chloride	0.2862	1.219
		Methyl Hydrazine	0.0918	0.391
		Nickel	0.1512	0.644
		Phenol	0.00864	0.0368
		POM	0.03	0.10
		Propionaldehyde	0.2052	0.874
		Selenium	0.702	2.99
		Sulfuric Acid	12.77	55.93
		2,3,7,8-TCDD	7.722E-09	3.29E-08

3. SN-01 and SN-02 are subject to 40 CFR, Part 60, Subpart D, Standards of Performance for fossil fuel-fired steam generators due to a heat input capacity of greater than 250 MMBtu/hr. Applicable provisions of Subpart D (Appendix A) include, but are not limited to the following [Regulation 19, §19.304, and 40 CFR Part 60]:

   a. PM emissions shall not exceed 0.1 lb/MMBtu. [40 CFR 60.42(a)(1)]

b. Opacity shall not exceed 20 percent except for one six-minute period per hour of not more than 27 percent opacity and as except as provided by 40 CFR 60.8 and 60.11. [40 CFR 60.42(a)(2)]
c. SO_2 emissions shall not exceed 1.2 lb/MMBtu. [40 CFR 60.43]
d. NO_X emissions shall not exceed 0.7 lb/MMBtu. [40 CFR 60.44(a)(3)]
e. The permittee shall install, calibrate, and maintain Continuous Emissions Monitoring Systems (CEMS) for NOx, SO_2, CO_2, and opacity. The CO_2 monitor and analyzer serve as the diluent in this system. [40 CFR 60.45(a)]
f. Excess opacity emissions are defined as any six minute period during which the average opacity emissions exceed 20%, except for one 6 minute average per hour of up to 27% opacity. [40 CFR 60.45(g)(1)]
g. Excess SO_2 emissions are defined as any 3-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard under 60.43 . [40 CFR 60.45(g)(2)]
h. Excess NO_X emissions are defined as any 3-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of NO_X as measured by a CEMS exceed the applicable standard under 60.44. [40 CFR 60.45(g)(3)]
i. Excess emission and monitoring system performance reports shall be submitted to the Department for every calendar quarter. Quarterly reports shall be postmarked by the 30th day following the end of the calendar quarter. Excess emissions are defined in 60.45(g). [40 CFR 60.45(g)]

4. Ç The permittee shall maintain records which demonstrate compliance with the SO_2 emission limits set in Specific Conditions # 1 and #3 . These records may be used by the Department for enforcement purposes. For Specific Condition #1 compliance shall be determined as the arithmetic average of three one-hour periods of SO_2 emissions as measured by the CEMS and converted to pounds per hour per 40 CFR Part 75. Data Substituted in accordance with 40 CFR Part 75 for missing and/or invalid data will not be used for compliance with Specific Condition #1 . For Specific Condition # 3, compliance shall be determined as the arithmetic average of three contiguous one-hour periods of SO_2 as measured by a CEMS and converted to pounds per MMBtu per 40 CFR Part 60. These records shall be kept on site and shall be provided to Department personnel upon request. Records shall be submitted in accordance with General Provision #7. [Regulation 19, §19.705, and 40 CFR Part 52, Subpart E]

5. The permittee shall maintain records which demonstrate compliance with the NO_X emission limits set in Specific Conditions #1 and #3. These records may be used by the Department for enforcement purposes. For Specific Condition #1, compliance shall be determined as the arithmetic average of three contiguous one-hour periods of NO_x emissions as measured by the CEMS and converted to pounds per hour per 40 CFR Part 75. Data Substituted in accordance with 40 CFR Part 75 for missing and/or invalid data will not be used for compliance with Specific Condition #1. For Specific Condition #3, compliance shall be determined as the arithmetic average of three contiguous one-hour

periods of NOx as measured by a CEMS and converted to pounds per MMBtu per 40 CFR Part 60. These records shall be kept on site and shall be provided to Department personnel upon request. Records shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

6. Ç The permittee shall not cause to be discharged to the atmosphere from the boilers any emissions which exhibit an opacity greater than 20 percent when firing coal or No. 2 fuel oil. The opacity shall not exceed 20 percent (6-minute average), except for one 6-minute period per hour not to exceed 27 percent. Opacity exceedances shall be reported in accordance with Specific Condition #7. [§19.503 of Regulation 19, and 40 CFR Part 52, Subpart E and 40 CFR 60.42(a)(2)]

7. Ç The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) for measuring opacity of emissions and all SO_2, NOx, and CO_2 emissions from SN-01 and SN-02 and record the output of the system. The CO_2 monitor and analyzer serve as the diluent in this system. This CEMS shall comply with the Air Division's "Continuous Emission Monitoring Systems Conditions". A copy is provided in Appendix B. The permittee shall report all excess emissions as defined by 40 CFR 60.45(g)(1), (2), and (3) and in accordance with 40 CFR 60.7(c).

Except for opacity, the permittee must report all excess emissions including those excess emissions caused by startups, shutdowns, and malfunctions. For opacity, all exceedances must be reported in the quarterly reports including those attributable to startup, shutdown, and malfunction. Only those opacity exceedances that are not attributable to startup, shutdown, and malfunction will be used for calculating the percentage of compliance with the NSPS opacity limit. Opacity exceedances would not be reported under §19.601 of Regulation 19 for startup, shutdown, and malfunction.

The number of startup and shutdown occurrences that occur at this facility have historically ranged from 12 to 24 per year. In general, startup begins when the ID and FD fans are started with the intent to fire the unit. Normally, startup ends when the unit achieves stable operation and the following operating parameters are met: (1) the electrostatic precipitator is placed in service, and (2) startup oil is no longer necessary to support combustion. Duct sweeps are usually considered a part of the startup operation. For these units, shutdown normally begins when the unit load or output is reduced with the intent of removing the unit from service, or when the unit trips as the result of sudden and unforeseen failure or malfunction. Shutdown ends when the unit is no longer combusting fuel and fan operation is no longer required. [§19.703 of Regulation 19, 40 CFR Part 52, Subpart E, and A.C.A. §8- 4-203 as referenced by §8-4-304 and §8-4-311]

8. The permittee shall submit quarterly excess emissions and monitoring systems performance reports to the Department. The reports shall include the magnitude of excess emissions, date and time of commencement and completion of each time period of excess emissions, process operating time during reporting period, date and time of each period during which the CEMS were inoperative, identification of each period of excess

emissions that occurs during startup, shutdown, and malfunctions of the units, nature and cause of any malfunction (if known), and the corrective action or preventative measure adopted. [§19.304 of Regulation 19, and 40 CFR 60.7] Reports shall be submitted via email to airsubmission@adeq.state.ar.us or sent to the following address:

Arkansas Department of Environmental Quality
Air Division
Attn: Compliance Inspector Supervisor
5301 Northshore Drive
North Little Rock, AR 72118-5317

9. Ç The permittee shall ensure that all continuous emission and opacity monitoring systems are in operation and monitoring all unit emissions or opacity at all times that the affected unit combusts any fuel, except during periods of calibration, quality assurance, preventative maintenance or repair. [§19.304 of Regulation 19, and 40 CFR 75.10]

10. The permittee shall not exceed the emission rates, when operating under Scenario II: No. 2 fuel oil or bio-diesel firing, set forth in the following table. [§19.501 of Regulation 19 et seq., and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
01 (C1)	Unit 1 Boiler – No. 2 Fuel Oil or Bio-diesel	PM_{10}	24.1	105.5
		SO_2	573.0	2509.7
		VOC	1.9	8.1
		CO	36.5	159.9
		NO_x	175.2	767.3
		Lead	0.1	0.1
02 (C2)	Unit 2 Boiler – No. 2 Fuel Oil or Bio-diesel	PM_{10}	24.1	105.5
		SO_2	573.0	2509.7
		VOC	1.9	8.1
		CO	36.5	159.9
		NO_x	175.2	767.3
		Lead	0.1	0.1

11. The permittee shall not exceed the emission rates, when operating under Scenario II: No. 2 fuel oil or bio-diesel firing, set forth in the following table. [§18.801 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
01 (C1)	Unit 1 Boiler – No. 2 Fuel Oil or Bio-diesel	PM	24.1	105.5
		Arsenic	0.004	0.01752
		Benzene	0.001562	0.006842
		Beryllium	0.003	0.01314
		Cadmium	0.003	0.01314

SN	Description	Pollutant	lb/hr	tpy
		Chromium	0.003	0.01314
		Formaldehyde	0.350366	1.534605
		Manganese	0.006	0.02628
		Mercury	0.003	0.01314
		Nickel	0.003	0.01314
		POM	0.024088	0.105504
		Selenium	0.015	0.0657
		Sulfuric Acid	8.775419	38.43634
02 (C2)	Unit 2 Boiler – No. 2 Fuel Oil or Bio-diesel	PM	24.1	105.5
		Arsenic	0.004	0.01752
		Benzene	0.001562	0.006842
		Beryllium	0.003	0.01314
		Cadmium	0.003	0.01314
		Chromium	0.003	0.01314
		Formaldehyde	0.350366	1.534605
		Manganese	0.006	0.02628
		Mercury	0.003	0.01314
		Nickel	0.003	0.01314
		POM	0.024088	0.105504
		Selenium	0.015	0.0657
		Sulfuric Acid	8.775419	38.43634

12. The permittee shall maintain records which demonstrate compliance with the SO_2 emission limits set in Specific Condition #10. These records may be used by the Department for enforcement purposes. For Specific Condition #10, compliance shall be determined as the arithmetic average of three contiguous one-hour periods of SO_2 emissions as measured by the CEMS and converted to pounds per hour per 40 CFR Part 75. Data substituted in accordance with 40 CFR Part 75 for missing and/or invalid data will not be used for compliance with Specific Condition #10. These records shall be kept on site and shall be provided to Department personnel upon request. Records shall be submitted in accordance with General Provisions #6 and #7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

13. The permittee shall maintain records which demonstrate compliance with the NO_X emission limits set in Specific Condition #10. These records may be used by the Department for enforcement purposes. For Specific Condition #10, compliance shall be determined as the arithmetic average of three contiguous one-hour periods of NO_X emissions as measured by the CEMS and converted to pounds per hour per 40 CFR Part 75. Data substituted in accordance with 40 CFR Part 75 for missing and/or invalid data will not be used for compliance with Specific Condition #10. These records shall be kept on site and shall be provided to Department personnel upon request. Records shall be submitted in accordance with General Provisions #6 and #7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

14. The permittee may burn No. 2 fuel oil or bio-diesel during startup, shutdown, and malfunction. For all other No. 2 fuel oil burning activities, the permittee shall submit a request to EPA for a determination regarding the applicability of NSPS Subpart D limits and testing requirements during the coal and fuel oil and fuel oil only firing scenarios. Within 30 days of permit issuance, this request shall be submitted to EPA and a copy shall be submitted to the Department. The facility submitted a request for determination on May 25, 2005. The permittee may burn No. 2 fuel oil or bio-diesel until a determination is made by EPA. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

15. The permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the scenario under which the facility or source is operating. [40 CFR 70.6(a)(9)(i), §26.7 of Regulation #26, and in accordance with General Provision #17]

16. The permittee shall not exceed 91 ,454.4 tons/year of SO_2 emissions for any consecutive twelve month period from SN-0 1 and SN-02 when firing coal, No. 2 fuel oil or bio-diesel. [§ 19.501 of Regulation 19 *et seq*, and 40 CFR Part 52, Subpart E]

17. The permittee shall maintain monthly records which demonstrate compliance with the limit set in Specific Condition #16. These records may be used by the Department for enforcement purposes. The records shall be updated no later than the last day of the month following the month to which the records pertain. The records shall be kept on site, and shall be provided to Department personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

18. The permittee shall not exceed 53,348.4 tons/year of NO_X emissions for any consecutive twelve month period from SN-01 and SN-02 when firing coal or No. 2 fuel oil or bio-diesel. [§19.501 of Regulation 19 et seq., and 40 CFR Part 52, Subpart E]

19. The permittee shall maintain monthly records which demonstrate compliance with the limit set in Specific Condition #18. These records may be used by the Department for enforcement purposes. The records shall be updated no later than the last day of the month following the month to which the records pertain. The records shall be kept on site, and shall be provided to Department personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

20. Ç SN-01 and SN-02 are subject to and shall comply with all applicable provisions of the Acid Rain Program. [§19.304 of Regulation 19, and 40 CFR Parts 72, 73, 75, 76, and 77]

21. The permittee shall submit the required Electronic Data Reports to EPA Headquarters. [§19.304 of Regulation 19, and 40 CFR 75]

22. The permittee will perform Relative Accuracy tests in accordance with 40 CFR Part 75. This relative accuracy test will meet the requirements under 40 CFR Part 60, Subpart D. [§19.304 of Regulation 19, and 40 CFR 75.10]

23. The permittee shall determine and record the heat input to each affected unit (SN-01 and SN-02) for every hour or part of an hour any fuel is combusted following the procedures in Appendix F of 40 CFR Part 75. This calculation will meet the requirements under 40 CFR Part 60, Subpart D. [§19.304 of Regulation 19, and 40 CFR 75.10(c)]

24. The permittee shall test SN-01 and SN-02 for CO while operating under Scenario I: Coal Firing without any oil firing (except for flame stabilization, to change bowl mills or other activities) and while operating at 90% or greater capacity. Emission results shall be extrapolated to correlate with 100% of the permitted capacity derived from the average of three, one-hour tests to determine compliance. This testing shall be conducted within 180 days of permit issuance and every five years thereafter. These tests shall be performed using EPA Reference Method 10, and shall be conducted in accordance with Plantwide Condition #3. [§19.702 of Regulation 19 and 40 CFR Part 52, Subpart E]

25. The permittee shall test SN-01 and SN-02 for PM and PM_{10} while operating under Scenario I: Coal Firing without any oil firing (except for flame stabilization, to change bowl mills or other activities) and while operating at 90% or greater capacity. Emission results shall be extrapolated to correlate with 100% of the permitted capacity to determine compliance. The PM test shall be performed using EPA Reference Methods 5 and 202. The PM_{10} test shall be performed using EPA Reference Methods 201A and 202. These tests shall be conducted in accordance with Plantwide Condition #3. This testing shall be conducted within 180 days of permit issuance and every year thereafter. [§19.702 of Regulation 19 and 40 CFR Part 52, Subpart E]

26. The ash content of the coal or coal blend shall not exceed 15.09 lb/MMBtu and the sulfur content of the coal or coal blend shall not exceed 0.72%, unless the following equation can be met:

$$[((0.1 \times S) - 0.03) \times 8950] + [(10 \times (1-0.995) \times A \times 8950 \times (1/C))] \leq 714.0 \text{ lb/hr}$$

where S = sulfur %,
A = ash %, and
C = coal heat value in MMBtu/ton.

The permittee shall maintain records that demonstrate compliance with this specific condition. These records shall include the certificate of analysis and, if applicable, the calculation results. If blending is necessary, the permittee shall also keep records of the data used to obtain the blended coal properties. If coal samples are used to demonstrate compliance with blended coal, the sampling method must be approved in advance by the Department. These records shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

27. The permittee shall monitor the opacity of SN-01 and SN-02 using a continuous opacity monitoring system. The permittee shall initiate corrective action when the measured opacity is greater than 20% for a one-hour average, and shall report any excursions where the opacity is greater than 20% on a three-hour average. Corrective action may include, but is not limited to, ESP inspection, returning tripped ESP sections to service, ash removal system evaluation, and load reduction, if necessary. During startup when the ESP is offline, the corrective actions referenced above will not be required but startup shall be minimized. The permittee shall maintain records of the measured opacity and any corrective actions taken. A monitoring report shall be submitted to the Department in accordance with General Provision #7 and shall include the following per 40 CFR §64.9(a)(2):

    The information required under 40 CFR §70.6(a)(3)(iii);

    Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

    Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

    A description of the actions taken to implement a QIP, if required, during the reporting period as specified in §64.8. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring. A QIP shall be required if the excess emissions for opacity, as reported on the Quarterly Excess Emissions Report, exceeds 5% of the unit operating time.

All opacity exceedances must be reported in the quarterly reports including those attributable to startup, shutdown, and malfunction. Opacity exceedances would not be reported under §19.601 of Regulation 19 for startup, shutdown, and malfunction. In accordance with §64.7(d)(2), a determination may be made by the Department regarding whether the permittee has used acceptable procedures in response to an excursion or an exceedance. [§19.304 of Regulation 19, and 40 CFR Part 64]

28. The opacity for SN-01 and SN-02 shall not exceed 20% opacity except that emissions greater than 20% opacity but not exceeding 60% opacity will be allowed for not more than six (6) minutes in the aggregate in any consecutive 60-minute period, provided such emissions will not be permitted more than three (3) times during any 24-hour period. However, the opacity limits imposed by this condition will be held in abeyance provided

that opacity does not exceed 20% except that emissions greater than 20% opacity but not exceeding 27% opacity will be allowed for not more than one 6-minute period per hour, provided such emissions will not be permitted more than ten (10) times per day. Violations of this condition may be allowed as a direct result of unavoidable upset conditions in the nature of the process, or unavoidable and unforeseeable breakdown of any air pollution control equipment or related operating equipment, or as a direct result of shutdown or start-up of the operating unit, provided the following requirements are met:

a. Such occurrence, in the case of unavoidable upset in or breakdown of equipment, shall have been reported to the Department by means of a notification delivered by phone, fax, or email by the end of the next business day after the discovery of the occurrence.

b. The facility shall submit to the Department, at its request, a full report of such occurrence, including a statement of all known causes and of the scheduling and nature of the actions to be taken to minimize or eliminate future occurrences, including, but not limited to, action to reduce the frequency of occurrence of such conditions, to minimize the amount by which said limits are exceeded, and to reduce the length of time for which said limits are exceeded.

c. In the case of shutdown for necessary scheduled maintenance, the intent to shutdown shall be reported to the Department at least twenty-four (24) hours prior to the shutdown; provided, however, that the exception provided by this condition shall only apply in those cases where maximum reasonable effort has been made to accomplish such maintenance during periods of non-operation of any related source operation or where it would be unreasonable or impossible to shut down the source operation during the maintenance period. Any information which is considered a trade secret under 8-4-308 shall be submitted with an affidavit containing the information of Regulation 18.1402(B).

d. Demonstrates to the satisfaction of the Department that the emissions resulted from:

    i. Equipment malfunction or upset and are not the result of negligence or improper maintenance;

    ii. Physical constraints on the ability of a source to comply with the emission standard, limitation or rate during startup or shutdown;

And that all reasonable measures have been taken to immediately minimize or eliminate the excess emissions. Opacity exceedances shall be reported in accordance with Specific Condition #7. [§18.102(C), §18.501, and §18.1101 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

29. Unit 1 (SN-01) and Unit 2 (SN-02) are subject to and shall comply with all applicable requirements of 40 CFR Part 63 Subpart UUUUU - *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units*. These requirements include those outlined in Specific Conditions 30 through 64 below. Unit 1 and Unit 2 must be in compliance with all applicable requirements by the compliance date outlined in Specific Condition 30 below. For the purposes of Subpart UUUUU, both Unit 1 and Unit 2 are categorized as existing coal-fired EGUs designed for a coal with a heating value greater than or equal to 8,300 Btu/lb. [Regulation 19 §19.304 and 40 CFR §§63.9981, 63.9982, and 63.9990]

30. An extension of compliance for 40 CFR Part 63 Subpart UUUUU has been granted by ADEQ for Unit 1 (SN-01) and Unit 2 (SN-02) in accordance with the provisions of 40 CFR §63.6(i)(4). Accordingly, the compliance date for all applicable provisions of 40 CFR Part 63 Subpart UUUUU, for Unit 1 (SN-01) and Unit 2 (SN-02), is established as April 16, 2016. The permittee is not required to demonstrate compliance with the provisions of Subpart UUUUU, as outlined in Specific Conditions 31 through 64, until this date, or later, as established by the provisions of Subpart UUUUU. [Regulation 19 §19.304 and 40 CFR §63.6(i)]

31. Unit 1 (SN-02) and Unit 2 (SN-02) shall comply with the applicable emission limits in Table 2 to Subpart UUUUU. For category (a) each unit shall comply with either the limit for filterable particulate matter, the limit for total non-Hg HAP metals, or the limits for individual HAP metals. For category (b) each unit shall comply with the limit for HCl. Where two emissions limits are specified for a particular pollutant (e.g., a heat input-based limit in lb/MMBtu and an electrical output-based limit in lb/MWh), the permittee may elect to demonstrate compliance with either emission limit. [Regulation 19 §19.304 and 40 CFR §§63.9991and 63.10000(a)]

Table 2 Requirements for existing coal-fired EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb		
For the following pollutants. . .	You must meet the following emission limits and work practice standards. . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5. . .
a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh.	Collect a minimum of 1 dscm per run.
OR	OR	
Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
OR	OR	
Individual HAP metals:		Collect a minimum of 3 dscm per run.

Table 2 Requirements for existing coal-fired EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb		
For the following pollutants. . .	You must meet the following emission limits and work practice standards. . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5. . .
Antimony (Sb)	8.0E-1 lb/Tbtu or 8.0E-3 lb/GWh.	
Arsenic (As)	1.1E0 lb/Tbtu or 2.0E-2 lb/GWh.	
Beryllium (Be)	2.0E-1 lb/Tbtu or 2.0E-3 lb/GWh.	
Cadmium (Cd)	3.0E-1 lb/Tbtu or 3.0E-3 lb/GWh.	
Chromium (Cr)	2.8E0 lb/Tbtu or 3.0E-2 lb/GWh.	
Cobalt (Co)	8.0E-1 lb/Tbtu or 8.0E-3 lb/GWh.	
Lead (Pb)	1.2E0 lb/Tbtu or 2.0E-2 lb/GWh.	
Manganese (Mn)	4.0E0 lb/Tbtu or 5.0E-2 lb/GWh.	
Nickel (Ni)	3.5E0 lb/Tbtu or 4.0E-2 lb/GWh.	
Selenium (Se)	5.0E0 lb/Tbtu or 6.0E-2 lb/GWh.	
b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run.
		For ASTM D6348-03 3or Method 320, sample for a minimum of 1 hour.
OR	OR	
Sulfur dioxide (SO_2) 4	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2CEMS.
c. Mercury (Hg)	1.2E0 lb/Tbtu or 1.3E-2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.

32. Unit 1 (SN-02) and Unit 2 (SN-02) shall comply with the applicable work practice standards in Table 3 to Subpart UUUUU. [Regulation 19 §19.304 and 40 CFR §63.9991(a)(1)]

Table 3 requirements for existing coal-fired EGUs	
If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired EGU during startup	You must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels, either natural gas or distillate oil or a combination of clean fuels for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).
4. A coal-fired EGU during shutdown	You must operate all CMS during shutdown. Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use) or at the point of no fuel being fired in the boiler. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler. During shutdown, you must operate all applicable control technologies while firing coal, residual oil, or solid oil-derived fuel. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).

33. Unit 1 (SN-02) and Unit 2 (SN-02) shall comply with the applicable operating limits in Table 4 to Subpart UUUUU. These limits are only applicable to Units 1 and 2 if the permittee elects to utilize CPMS to demonstrate compliance with the applicable PM limit. [Regulation 19 §19.304 and 40 CFR §63.9991(a)(1)]

Table 4 requirements for existing EGUs	
If you demonstrate compliance using. . .	You must meet these operating limits. . .
1. PM CPMS for an existing EGU	Maintain the 30-boiler operating day rolling average PM CPMS output at or below the highest 1-hour average measured during the most recent performance test demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

34. The permittee shall meet the following general requirements of Subpart UUUUU. [Regulation 19 §19.304 and 40 CFR §63.10000]

a. Units 1 and 2 must be in compliance with the applicable emission limits and operating limits in Subpart UUUUU. These limits apply at all times except during periods of startup or shutdown. The applicable work practice requirements of Table 3 must be met during periods of startup and shutdown. [§63.10000(a)]

b. At all times Units 1 and 2 and any associated air pollution control equipment must be operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [§63.10000(b)]

c. As coal-fired units, initial performance testing is required for Units 1 and 2 for all pollutants, to demonstrate compliance with the applicable emission limits. [§63.10000(c)]

i. For coal-fired EGUs you may conduct initial performance testing in accordance with §63.10005(h) to determine whether the unit qualifies as a low emitting EGU (LEE) for one or more applicable emissions limits. The exceptions of §63.10000(c)(1)(i)(A) and (B) are not applicable to Units 1 and 2.

ii. For a qualifying LEE for Hg emissions limits, a 30-day performance test using Method 30B must be conducted at least once every 12 calendar months to demonstrate continued LEE status.

iii. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

iv. If a coal-fired EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you most monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or compliance testing repeated quarterly.

v. If a coal-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), initial and continuous compliance may be demonstrated through the use of an HCl CEMS, installed and operated in accordance with Appendix B to Subpart UUUUU. As an alternative to HCl CEMS, initial and continuous compliance may be demonstrated by conducting an initial and periodic quarterly performance stack tests for HCl.

vi. For a coal-fired EGU which does not qualify as a LEE for Hg, initial and continuous compliance must be demonstrated through the use of a Hg CEMS or a sorbent trap monitoring system, in accordance with Appendix A to Subpart UUUUU.

d. If compliance is demonstrated with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), the permittee must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies if the permittee petitions the Administrator for alternative monitoring parameters under §63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B to 40 CFR Part 60 or 40 CFR Part 75 and that meet the requirements of §63.10010. Using the process described in §63.8(f)(4), the permittee may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in §63.10000(d) and, if approved, include those in the site-specific monitoring plan. The monitoring plan must address the provisions in §63.10000(d)(2) through (d)(5). [§63.10000(d)]

e. As part of the demonstration of continuous compliance, the permittee must perform periodic tune-ups of Unit 1 and Unit 2 according to §63.10021(e). [§63.10000(e)]

35. In response to an action to enforce the standards set forth in §63.9991 the permittee may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR §63.2. Appropriate penalties may be assessed, however, if the permittee fails to meet the burden of proving

all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims of injunctive relief. [Regulation 19 §19.304 and 40 CFR §63.10001]

a. To establish an affirmative defense in any action to enforce such a limit the permittee must timely meet the notification requirements in paragraph (b) of §63.10001, and must prove by a preponderance of evidence that the criteria in §63.10001(a)(1) through (9) have been met. [§63.10001(a)]

b. If an affected source experiences an exceedance of an applicable emission limit(s) under Subpart UUUUU during a malfunction, the owner or operator shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction or, if it is not possible to determine within two business days whether the malfunction caused or contributed to an exceedance, no later than two business days after the permittee knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period, if the owner or operator wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in § 63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance. [§63.10001(b)]

36. For Unit 1 and Unit 2, initial compliance must be demonstrated with each applicable emissions limit in Table 2 of Subpart UUUUU through performance testing. Where two emissions limits are specified for a particular pollutant (e.g., a heat input-based limit in lb/MMBtu and an electrical output-based limit in lb/MWh), the permittee may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of hourly electrical load data (megawatts); establishment of operating limits according to § 63.10011 and Tables 4 and 7 to Subpart UUUUU; and CMS performance evaluations. In all cases, the permittee must demonstrate initial compliance no later than the applicable date in paragraph (f) of §63.10005 for tune-up work practices for existing EGUs and by April 16, 2016 for other requirements for existing EGUs. [Regulation 19 §19.304 and 40 CFR §63.10005]

a. To demonstrate initial compliance with an applicable emissions limit in Table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. If you are required to establish operating limits (see paragraph (d) of §63.10005 and Table 4 to Subpart UUUUU), you must collect all applicable parametric data during the performance test period. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period. [§63.10005(a)(1)]

b. Ç To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (i.e. , an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO_2 or PM CEMS, the initial performance test consists of 30 boiler operating days of data collected by the initial compliance demonstration date specified in § 63.10005 with the certified monitoring system. [§63.1 0005(a)(2)]

i. The 30-boiler operating day CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO_2 emissions limit in Table 2 to Subpart UUUUU.

ii. If the permittee chooses to comply with an electrical output-based emission limit, hourly electrical load data must be collected during the performance test period.

37. If the permittee chooses to use performance testing to demonstrate initial compliance with the applicable emission limits in Table 2 to Subpart UUUUU for Unit 1 and/or Unit 2, the tests must be conducted according to §63.10007 and Table 5 to Subpart UUUUU. For the purposes of the initial compliance demonstration, test data and results from a performance test conducted prior to the date on which compliance is required may be used, provided that the conditions of §63.10005(b)(1) through (5) are fully met. [Regulation 19 §19.304 and 40 CFR §63.10005(b)]

38. If, for a particular emission or operating emission limit, the permittee is required to (or elects to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of §§ 63.10010(b) through (h), an additional performance evaluation of the CMS is not required under Subpart UUUUU. [Regulation 19 §19.304 and §63.10005(d)]

a. Ç For an affected coal-fired EGU, initial compliance with the applicable SO_2 or HCl emissions limit in Table 2 to Subpart UUUUU may be demonstrated through use of an SO_2 or HCl CEMS installed and operated in accordance with 40 CFR Part 75 or Appendix B to Subpart UUUUU. Compliance with a filterable PM emissions limit in Table 2 of Subpart UUUUU may be demonstrated through use of a PM CEMS installed, certified, and operated in accordance with §63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS data, expressed in units of the standard (see §63.10007(e)), meets the applicable SO_2, PM, or HCl emissions limit in Table 2 to Subpart UUUUU. Equation 19-19 of Method 19 in Appendix A-7 to Subpart UUUUU must be used to calculate the 30-boiler operating day average emissions rate. For this calculation, the term Ehj in Equation 19-19 must be in the same units of measure as the applicable HCl emission limit in Table 2 of Subpart UUUUU. [§63.10005(d)(1)]

b. Ç For affected coal-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 2 to Subpart UUUUU using initial performance testing and continuous monitoring with PM CPMS: [§63.10005(d)(2)]

i. Initial compliance must be demonstrated by no later than the applicable date specified in §63.9984(f) for existing units. Based on the compliance date extension granted by ADEQ, initial compliance for Unit 1 and Unit 2 must be demonstrated by no later than October 13, 2016.

ii. Continuous compliance must be demonstrated with the PM CPMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the emission limit with which the permittee chooses to comply.

iii. The permittee must repeat the performance test annually for the selected pollutant emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

c. For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 2 of Subpart UUUUU using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in §63.9984(f) for existing EGUs. Based on the compliance date extension granted by ADEQ, initial compliance for Unit 1 and Unit 2 must be demonstrated by no later than October 13, 2016. Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of Appendix A to Subpart UUUUU), meets the applicable Hg emission limit in Table 2 to Subpart UUUUU. [§63.10005(d)(3)]

39. Unit 1 and Unit 2 are subject to the work practice standards in Table 3 of Subpart UUUUU. As part of the initial compliance demonstration, the permittee must conduct a

performance tune-up of Unit 1 and Unit 2 according to §63.10021(e). [Regulation 19 §19.304 and §63.10005(e)]

40. For existing affected sources a tune-up may occur prior to April 16, 2012, so that existing sources without neural networks have up to 42 calendar months (3 years from promulgation plus 180 days) or, in the case of units employing neural network combustion controls, up to 54 calendar months (48 months from promulgation plus 180 days) after the date that is specified for your source in § 63.9984 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 9 to this subpart to demonstrate compliance with this requirement. If a tune-up occurs prior to such date, the source must maintain adequate records to show that the tune-up met the requirements of this standard. [Regulation 19 §19.304 and §63.10005(f)]

41. If the permittee wishes to qualify for low emitting EGU (LEE) status for one or more pollutants with emission limits for existing EGUs, then the procedures of §63.10005(h)(1) through (5) must be followed, as applicable. [Regulation 19 §19.304 and §63.10005(h)]

42. Startup and shutdown of Unit 1 and Unit 2 must follow the requirements given in Table 3 to Subpart UUUUU. [Regulation 19 §19.304, 40 CFR §63.10011 (g), and 40 CFR §63.10005(j)]

43. The permittee must submit a Notification of Compliance Status summarizing the results of the initial compliance demonstration, as provided in §63.10030. [Regulation 19 §19.304, 40 CFR §63.10011(e), and 40 CFR §63.10005(k)]

44. The permittee shall comply with the following requirements for subsequent performance tests and tune-ups. [Regulation 19, §19.304 and 40 CFR §63.10006]

    a. If the permittee elects to utilize PM CPMS to monitor continuous performance with an applicable emission limit as provided under §63.10000(c), then all applicable performance tests must be conducted according to Table 5 to Subpart UUUUU and §63.10007 at least once every year. [§63.10006(a)]

    b. For units meeting the LEE requirements of §63.10005(h), the permittee must repeat the performance test once every three years (once every year for Hg) according to Table 5 of Subpart UUUUU and §63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur: [§63.10006(b)]

        i. For all pollutant emission limits except for Hg, the permittee must conduct emissions testing quarterly, except as otherwise provided in §63.10021(d)(1).

        ii. For Hg, the permittee must install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with Appendix

A to Subpart UUUUU, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the permittee must conduct Hg emissions testing quarterly, except as otherwise provided in §63.10021(d)(1). The permittee must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status.

c. Ç Except where paragraphs (a) or (b) of §63.10006 apply, or where the permittee installs, certifies, and operates a PM CEMS to demonstrate compliance with a filterable PM emissions limit, the permittee must conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 to Subpart UUUUU, §63.10007, and §63.10000(c), except as otherwise provided in §63.10021(d)(1). [§63.10006(c)]

d. Ç Except where paragraph (b) of §63 .10006 applies, if the permittee does not utilize either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, the permittee must conduct all applicable periodic HCl emissions tests according to Table 5 of Subpart UUUUU and §63.1 0007 at least quarterly, except as otherwise provided in §63 .10021(d)(1). [§63 .10006(d)]

e. Ç Unless the permittee follows the requirements listed in paragraphs (g) and (h) of §63.10006, performance tests required at least once every 3 calendar years must be completed within 35 to 37 calendar months after the previous performance test, performance tests required at least every year must be completed within 11 to 13 calendar months after the previous performance test, and performance tests required at least quarterly must be completed within 80 to 100 calendar days after the previous performance test, except as otherwise provided in §63.10021(d)(1). [§63.10006(f)]

f. Ç If the permittee elects to demonstrate compliance using emissions averaging under §63.10009, then the permittee must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (f) of §63.10006. [§63.10006(g)]

g. If a performance test on a non-mercury LEE shows emission in excess of 50 percent of the emission limit and if the permittee chooses to reapply for LEE status, then subsequent performance tests must be conducted at the appropriate frequency given in section (c) through (e) of §63.10006 for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria. [§63.10006(h)]

h. Ç As Unit 1 and Unit 2 are subject to an applicable tune-up work practice standard, then the permittee must conduct a performance tune-up for each unit according to §63.10021(e). [§63.10006(i)]

i. For EGUs not employing neural network combustion optimization during normal operation, each performance tune-up specified in §63.10021(e) must be conducted no more than 36 calendar months after the previous performance tune-up.

ii. For EGUs employing neural network combustion optimization systems during normal operation, each performance tune-up specified in §63.10021(e) must be conducted no more than 48 calendar months after the previous performance tune-up.

i. The permittee must report the results of performance tests and performance tune-ups within 60 days after the completion of the performance tests and performance tune-ups. The reports for all subsequent performance tests must include all applicable information required in §63.10031. [§63.10006(j)]

45. Ç When conducting performance tests for the purposes of Subpart UUUUU, the permittee shall comply with the applicable provisions of 40 CFR §63.10007. [Regulation 19 §19.304 and 40 CFR §63.10007]

46. Ç If the permittee elects to utilize emissions averaging for the purposes of demonstrating compliance with the applicable emission limitations of Subpart UUUUU, the applicable provisions of 40 CFR §63.10009 shall be followed. [Regulation 19, §19.304 and 40 CFR §63.10009 and 40 CFR §63.10011 (e)]

47. The permittee shall comply with the applicable monitoring, installation, operation, and maintenance requirements of 40 CFR §63.10010. Both Unit 1 and Unit 2 utilize single-unit single-stack configurations. [Regulation 19 §19.304 and 40 CFR §63.10010]

48. Ç The permittee must demonstrate initial compliance with each applicable emission limit of Subpart UUUUU by conducting performance testing. [Regulation 19 §19.304 and 40 CFR §63.10011]

49. Ç If the permittee is subject to an operating limit in Table 4 to Subpart UUUUU, demonstrates compliance with HAP metals or filterable PM emissions limit(s) through performance stack tests, and elects to use a PM CPMS to demonstrate continuous performance, then the permittee must also establish a site-specific operating limit, in accordance with Table 4 to Subpart UUUUU, §63.10007, and Table 6 to Subpart UUUUU. The permittee may use only the parametric data recorded during successful performance tests (*i.e.* , tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit. [Regulation 19 §19.304 and 40 CFR §63.10011(b)]

50. Ç If the permittee uses CEMS or sorbent trap monitoring systems to measure a HAP (e.g., Hg or HCl) directly, the first 30-boiler operating day (or, if alternate emissions averaging is used for Hg, the 90-boiler operating day) rolling average emission rate obtained with certified CEMS after the applicability date set forth in Specific Condition #30, expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 2 to Subpart UUUUU. [Regulation 19 §19.304 and 40 CFR §63.10011(c)(1)]

51. Ç For a unit that uses a CEMS to measure SO_2 or PM emissions for initial compliance, the first 30 boiler operating day average emission rate obtained with certified CEMS after the applicability date set forth in Specific Condition #30, expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable SO_2 or filterable PM emission limit in Table 2 of Subpart UUUUU. [Regulation 19 §19.304 and 40 CFR §63.1001 1(c)(2)]

52. Ç For candidate LEE units, the permittee shall use the results of the performance testing described in §63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 2 to Subpart UUUUU and to determine whether the units qualifies for LEE status. [Regulation 19 §19.304 and 40 CFR §63.10011(d)]

53. RESERVED

54. Ç The permittee must determine the fuel whose combustion produces the least uncontrolled emissions, i.e., the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown. The determination of the cleanest fuel may take safety considerations into account. [Regulation 19 §19.304 and 40 CFR §63.10011(f)]

55. Ç RESERVED

56. Ç The permittee shall monitor and collect data to demonstrate continuous compliance in accordance with §63.10020. [Regulation 19 §19.304 and 40 CFR §63.10020]

57. Ç The permittee must demonstrate continuous compliance with each applicable emissions limit, operating limit, and work practice standard in Tables 2 through 4 to Subpart UUUUU, according to the monitoring specified in Tables 6 and 7 to Subpart UUUUU and paragraphs (b) through (g) of §63.10021. [Regulation 19 §19.304 and 40 CFR §63.10021]

   a. Ç Except as otherwise provided in § 63 .1 0020(c), if the permittee uses a CEMS to measure SO_2, PM, HCl, HF, or Hg emissions, or uses a sorbent trap monitoring system to measure Hg emissions, continuous compliance must be demonstrated by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate,

CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Equation 8 of Subpart UUUUU should be used to determine the 30- (or, if applicable, 90-) boiler operating day rolling average. [§63.10021(b)]

b. If the permittee uses a PM CPMS data to measure compliance with an operating limit in Table 4 to this subpart, the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control must be recorded. Continuous compliance must be demonstrated by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Equation 9 of Subpart UUUUU should be used to determine the 30 boiler operating day average. [§63.10021(c)]

c. If the permittee uses quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 2 to Subpart UUUU, [§63.10021(d)]

   i. The permittee may skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year; and

   ii. The permittee must conduct the performance test as defined in Table 5 to this subpart and calculate the results of the testing in units of the applicable emissions standard.

d. If the permittee must conduct periodic performance tune-ups of affected EGUs, as specified in paragraphs (e)(1) through (9) of §63.10021, perform the first tune-up as part of the initial compliance demonstration for the affected EGU. Notwithstanding this requirement, the first burner inspection may be delayed until the next scheduled unit outage provided that the requirements of §63.10005 are met. Subsequent inspections of the burner must be performed at least once every 36 calendar months unless the EGU employs neural network combustion optimization during normal operations in which case an inspection of the burner and combustion controls must be performed at least once every 48 calendar months. [§63.10021(e)]

e. The permittee must submit the reports required under § 63.10031 and, if applicable, the reports required under appendices A and B to this subpart. The electronic reports required by appendices A and B to this subpart must be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in § 63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under § 63.10031. [§63.10021(f)]

f. The permittee must report each instance in which it did not meet an applicable emissions limit or operating limit in Tables 2 through 4 to Subpart UUUUU or failed to conduct a required tune-up. These instances are deviations from the requirements of Subpart UUUUU. These deviations must be reported according to §63.10031. [§63.10021(g)]

g. The permittee must keep records as specified in §63.10032 during periods of startup and shutdown. [§63.10021(h)]

h. The permittee must provide reports as specified in §63.10031 concerning activities and periods of startup and shutdown. [§63.10021(i)]

58. If the permittee elects to utilize the emission averaging provision, continuous compliance shall be demonstrated in accordance with §63.10022. [Regulation 19 §19.304 and 40 CFR §63.10022]

59. If the permittee elects to utilize PM CPMS, the operating limit shall be established according to §63.10023(a) and (b). Continuous compliance shall be demonstrated according to §63.10023(c). [Regulation 19 §19.304 and 40 CFR §63.10023]

60. The permittee shall submit the following notifications. [Regulation 19 §19.304 and 40 CFR §63.10030]

a. The permittee shall submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4), and (6), and 63.9(b) through (h), as applicable, by the dates specified. [§63.10030(a)]

b. The permittee shall submit an initial notification for Unit 1 and Unit 2 by not later than 120 days after April 16, 2012. [§63.10030(b)]

c. When the permittee is required to conduct a performance test, a Notification of Intent to conduct a performance test must be submitted at least 30 days before the performance test is scheduled to begin. [§63.10030(d)]

d. When required to conduct an initial compliance demonstration as specified in §63.10011(a), the permittee must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report must contain the information specified in paragraphs (e)(1) through (7) to §63.10030, as applicable. [§63.10030(e)]

61. The permittee shall submit the following reports. [Regulation 19, §19.304 and 40 CFR §63.10031]

a. The permittee must submit each report in Table 8 to Subpart UUUUU, as applicable. If the permittee is required to (or elects to) continuously monitor Hg and/or HCl and/or HF emissions, the electronic reports required under Appendix A and/or Appendix B of Subpart UUUUU must also be submitted, at the specified frequency. [§63.10031(a)]

b. Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), the permittee must submit each report by the date in Table 8 to Subpart UUUUU and according to the requirements in paragraphs (b)(1) through (5) of §63.10031. [§63.10031(b)]

c. The compliance report must contain the information required in paragraphs (c)(1) through (4) of §63.10031. [§63.10031(c)]

d. For each excess emissions occurring at an affected source where a CMS is used to comply with that emission limit or operating limit, the compliance report specified in paragraph (c) must include the information required in §63.10(e)(3)(v). [§63.10031(d)]

e. Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 8 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. [§63.10031(e)]

f. As of January 1, 2012, and within 60 days after the date of completing each performance test, the permittee must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/index.html). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, the permittee must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority. [§63.10031(f)]

i. Within 60 days after the date of completing each CEMS (SO_2, PM, HCl, HF, and/or Hg) performance evaluation test, as defined in §63.2 and required by Subpart UUUUU, the permittee must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by Subpart UUUUU to EPA's WebFIRE database by using the CERDI that is accessed through EPA's CDX. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in §63.2 and as required in §63.10031.

ii. For a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st, the permittee must submit quarterly reports to EPA's WebFIRE database using the CERDI that is accessed through EPA's CDX. The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS. For such CEMS, the submission of these quarterly reports to EPA shall satisfy the requirements of Section III (D) and (E) of ADEQ's CEMS Conditions.

iii. Reports for an SO_2 CEMS, a Hg CEMS or sorbent trap monitoring system, an HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in Appendices A and B to Subpart UUUUU and §63.10021(f). For such CEMS, the submission of these quarterly reports to EPA shall satisfy the requirements of Section III (D) and (E) of ADEQ's CEMS Conditions.

iv. The permittee must submit the compliance reports required under §63.10031(c) and (d) and the notification of compliance status required under §63.10030(e) to EPA's WebFIRE database by using the CEDRI that is accessed through EPA's CDX. The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format.

v. All reports required by Subpart UUUUU not subject to the requirements of paragraphs (f)(1) through (f)(4) of §63.10031 must be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f)(1), (f)(2), and (f)(3) of §63.10031 in paper format.

g. If the permittee experienced a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description of each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. [§63.10031(g)]

62. The permittee shall keep the following records. [Regulation 19 §19.304 and 40 CFR §63.10032]

a. The permittee must keep records of the items outlined in paragraphs (a)(1) and (2) of §63.10032. If the permittee is required to (or elects to) continuously monitor Hg and/or HCl and/or HF emissions, the records required under Appendix A and/or Appendix B to Subpart UUUUU must also be kept. [§63.10032(a)]

i. A copy of each notification and report submitted to comply with Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance reports, according to the requirements in § 63.10(b)(2)(xiv).

ii. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in § 63.10(b)(2)(viii).

b. For each CEMS and CPMS, the permittee must keep records according to paragraphs (b)(1) through (4) of §63.10032. [§63.10032(b)]

i. Records described in § 63.10(b)(2)(vi) through (xi).

ii. Previous (i.e. , superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

iii. Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

iv. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

c. The permittee must keep the records required in Table 7 of Subpart UUUUU including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each applicable emission limit and operating limit. [§63.10032(c)]

d. For each EGU subject to an emission limit, the permittee must keep the records in paragraphs (d)(1) through (3) of §63.10032. [§63.10032(d)]

i. The permittee must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.

ii. If the permittee combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), records must be kept which document how the secondary material meets each of the legitimacy criteria. If the permittee combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), records must be kept as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), the permittee must keep a record which documents how the fuel satisfies the requirements of the petition process.

iii. For an EGU that qualifies as an LEE under § 63.10005(h), the permittee must keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.

e. If the permittee elects to average emissions consistent with §63.10009, then a copy of the emissions averaging implementation plan required in §63.1009(g) must be kept, along with all calculations required under §63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with §63.10022. [§63.10032(e)]

f. The permittee must keep records of the occurrence and duration of each startup and/or shutdown. [§63.10032(f)]

g. The permittee must keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment. [§63.10032(g)]

h. The permittee must keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. [§63.10032(h)]

i. The permittee must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown. [§63.10032(i)]

63. The permittee's records must be kept as follows. [Regulation 19 §19.304 and 40 CFR §63.10033]

a. Records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1). [§63.10033(a)]

b. As specified in §63.10(b)(1), each record must be kept for a period of 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. [§63.10033(b)]

c. Each record must be kept on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). The permittee can keep the records off-site for the remaining 3 years. [§63.10033(c)]

64. The general provisions of 40 CFR §§63.1 through 63.15 are applicable as specified in Table 9 to Subpart UUUUU. [Regulation 19 §19.304 and 40 CFR §63.10040]

65. The permittee shall sample and analyze each shipment of fuel oil or bio-diesel to determine the sulfur content. The sulfur content shall not exceed 0.5 weight percent. fuel oil sampling and analysis may be performed by the owner or operator of an affected unit, an outside laboratory, or a fuel supplier, provided that sampling is performed according to ASTM D4057. A shipment shall be defined as a 5,000 or 10,000 barrel lot delivered to a pipeline and pumped to a loading rack. *(Note: Vendor testing would satisfy this requirement as long as the sampling is performed according to ASTM D4057 and the facility is able to meet the requirements of Specific Condition #66.)* [§19.705 of

Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

66. The permittee shall maintain records of fuel oil analysis. These records shall be kept on site and made available to Department personnel upon request. These records may be used by the Department for enforcement purposes. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

67. No. 2 fuel oil or bio-diesel is the only fuel permitted for use in the Auxiliary boiler, SN-05. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

68. The permittee shall not exceed the emission rates set forth in the following table when burning No. 2 fuel oil or bio-diesel in the Auxiliary boiler, SN-05. [§19.501 of Regulation 19 et seq., and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
05 (C3)	Auxiliary Boiler	PM_{10}	4.5	19.4
		SO_2	105.2	460.8
		VOC	0.4	1.5
		CO	6.7	29.4
		NO_x	32.2	140.9
		Lead	0.1	0.1

69. The permittee shall not exceed the emission rates set forth in the following table when burning No. 2 fuel oil or bio-diesel in the Auxiliary boiler, SN-05. [§18.801 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
05 (C3)	Auxiliary Boiler	PM	4.5	19.4
		Arsenic	0.000735	0.003217
		Benzene	0.000287	0.001256
		Beryllium	0.000054	0.00024
		Cadmium	0.000551	0.002413
		Chromium	0.000551	0.002413
		Formaldehyde	0.06432	0.281722
		Manganese	0.001102	0.004825
		Mercury	0.000551	0.002413
		Nickel	0.000551	0.002413
		POM	0.004422	0.019369
		Selenium	0.002754	0.012062
		Sulfuric Acid	1.610985	7.056114

70. The opacity shall not exceed 20% from SN-05 as measured by EPA Reference Method 9. [§18.501 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

71. Weekly observations of the opacity from SN-05 shall be conducted by personnel familiar with the permittee's visible emissions, when operated more than one continuous hour. The permittee shall keep records of these observations. The permittee shall maintain personnel trained in (but not necessarily certified in) EPA Reference Method 9. If visible emissions are detected, then the permittee shall conduct a 6-minute opacity reading in accordance with EPA Reference Method 9. Records of the opacity observations shall be updated weekly, maintained on site, and made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

72. The permittee shall maintain records of when SN-05 is operated. These records shall be updated monthly, maintained on site, and made available to Department personnel upon request. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

SN-03, SN-06A, SN-06B, and SN-06C
Rail Car Rotary Dumper and Handling/Conveying Emissions

Source Description

SN-03, the coal for the White Bluff Steam Electric Station is received by rail. Each rail car is equipped with rotary couplings which enable the rail car rotary dumper to grasp one car at a time and empty it without removing the car from the train. The rail car rotary dumper, SN-03 (M1), is capable of emptying approximately 30 cars per hour. Emissions from the rail car rotary dumper are regulated under the State Implementation Plan (SIP), Regulation 19.

SN-06, minor emission sources at the plant include coal handling/conveying operations (not subject to NSPS Subpart Y). For this permitting action, SN-06 was separated into three sources: SN-06A, SN-06B, and SN-06C. SN-06A includes those emission points that were previously permitted as controlled with Amerclones, rotoclones, and water sprays. These emissions are now controlled with enclosures and a dust collector. This includes emission points M2, M3, M5, M6, M7, M8, M9, M16, M24, M25, M26, M27, and M28. SN-06B includes those emission points associated with the stacker reclaimer. This includes emission points M17, M18, M20, M21, M22, and M23. SN-06C includes the emissions associated with the storage piles, haul roads, and ash landfill. This includes emission points M4, M11, M19, M34, M35, and M36. The following emission points were removed from the permit since these emission points no longer exist at the White Bluff facility: M10 and M33. The following emission points were removed from the permit as sources of emissions since they are inoperable: M12, M13, and M14. The M15 Dead Storage Vault was removed from the permit as a source of emissions since it is completely enclosed, underground, and the rotoclone dust collector connected to it is inoperable. This rotoclone will be removed or abandoned in place. M32 was removed from the permit since it has been removed from service.

Specific Conditions

73. The permittee shall not exceed the emission rates set forth in the following table. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
03	Rail Car Rotary Dumper	PM_{10}	0.1	0.1
		VOC	1.3	2.2*
06A	Handling/ Conveying Emissions	PM_{10}	0.4	1.6
		VOC	0.2	2.2*
06B	Stacker/ Reclaimer Emissions	PM_{10}	0.5	2.0

SN	Description	Pollutant	lb/hr	tpy
06C	Storage Piles/Haul Road Emissions	PM_{10}	37.6	90.1

* Annual VOC emissions for SN-03 and SN-06A are bubbled together.

74. The permittee shall not exceed the emission rates set forth in the following table. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
03	Rail Car Rotary Dumper	PM	0.1	0.1
06A	Handling/ Conveying Emissions	PM	0.8	3.4
06B	Stacker/ Reclaimer Emissions	PM	1.0	4.3
06C	Storage Piles/Haul Road Emissions	PM	129.9	260.0

75. The permittee shall not cause to be discharged to the atmosphere any emissions which exhibit an opacity greater than 20 percent from SN-03. The opacity shall be measured in accordance with EPA Reference Method 9. [Regulation 19, §19.503, and 40 CFR Part 52, Subpart E]

76. The permittee shall use water and/or non-hazardous chemical sprays while the dumper is operating at SN-03, except when the ambient temperature is below 40 degrees F or while it is raining. Compliance with this condition shall represent compliance with this source's applicable requirements. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

77. Weekly observations of the opacity from source SN-06A shall be conducted by personnel familiar with the permittee's visible emissions. The permittee shall maintain personnel trained in (but not necessarily certified in) EPA Reference Method 9. If visible emissions from any of the towers, enclosed conveyors, or silos are detected, the permittee shall take action to identify the cause of the visible emissions, implement corrective action, and document if visible emissions were present following the corrective action. If visible emissions are still present following the corrective action, the permittee shall document that visible emissions do not appear to be in excess of 20% opacity and shall document that visible emissions did not cause a nuisance off-site. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this condition. These records shall be updated weekly, kept on site, and made available to

Department personnel upon request. [Regulation 19, §19.503, and 40 CFR Part 52, Subpart E]

a) The date and time of the observation.

b) If visible emissions were detected.

c) If visible emissions were detected, the cause of the visible emissions, the corrective action taken, and if the visible emissions were present following the corrective action.

d) If visible emissions were present following the corrective action, document that the visible emissions do not appear to be in excess of 20% opacity and document that the visible emissions do not cause a nuisance off-site.

e) The name of the person conducting the opacity observations.

78. The permittee shall conduct weekly observations of the opacity for the following source: SN-06B. Weekly observations from source SN-06B shall be conducted by personnel familiar with the permittee's visible emissions. The permittee shall maintain personnel trained in (but not necessarily certified in) EPA Reference Method 9. If visible emissions from stackout, reclaiming, or any of the belts or transfer points are detected, the permittee shall take action to identify the cause of the visible emissions, implement corrective action, and document if visible emissions were present following the corrective action. If visible emissions are still present following the corrective action, the permittee shall document that visible emissions do not cause a nuisance beyond the property boundary. Under normal conditions, off-site opacity less than or equal to 5% shall not be considered a nuisance. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this condition. These records shall be updated weekly, kept on site, and made available to Department personnel upon request. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

a) The date and time of the observation.

b) If visible emissions were detected.

c) If visible emissions were detected, the cause of the visible emissions, the corrective action taken, and if the visible emissions were present after the corrective action was taken.

d) If visible emissions were present following the corrective action, document that the visible emissions do not cause a nuisance beyond the property boundary.

e) The name of the person conducting the opacity observations.

79. The permittee shall not operate in a manner such that fugitive emissions from the storage piles, pile operations (such as operation of mobile equipment upon the storage pile), and haul road (SN-06C) would cause a nuisance off-site. Under normal conditions, off-site opacity less than or equal to 5% shall not be considered a nuisance. The permittee shall use water sprays or other techniques as necessary to control fugitive emissions. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

80. The VOC content of the dust suppressant chemical foam spray used at SN-03 and SN-06A shall not exceed 0.12 lb VOC/gal. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

81. The permittee shall maintain Material Safety Data Sheets which demonstrate compliance with Specific Condition #80. [Regulation 19, §19.705 and 40 CFR Part 52, Subpart E]

82. The dust suppressant chemical foam spray used at SN-03 and SN-06A shall not contain any hazardous air pollutants. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

83. The permittee shall maintain Material Safety Data Sheets which demonstrate compliance with Specific Condition # 82. [Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

84. Emissions of VOC from the usage of the dust suppressant chemical foam spray at SN-03 and SN-06A shall not exceed 2.2 tons of VOC per consecutive 12 month period. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

85. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #84. These records shall be updated no later than the last day of the month following the month to which the records pertain. Twelve month rolling totals and each individual month's data shall be kept on site, and shall be made available to Department personnel upon request. The twelve month rolling totals and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

86. The permittee shall comply with the maintenance plan submitted to the Department for the rotary car dumper. The requirements shall include, but are not limited to, the inspection of the spray nozzles for pluggage. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

87. The permittee shall not operate the following emission sources: M12 Dead Storage Hopper 4A, M13 Dead Storage Hopper 3A, and M14 Dead Storage Hopper 2A. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

88. The permittee shall use the foam sprays while the dumper (SN-03) is in operation except when the ambient temperature is below 40 degrees F or while it is raining. [§19.303 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

89. Total traffic associated with activated carbon deliveries, halide solution deliveries, and fly ash trucks hauling ash to the on-site landfill shall not exceed 63,586 vehicle miles traveled per consecutive twelve (12) month period on paved roads and 21,507 vehicle miles traveled per consecutive twelve (12) month period on unpaved roads. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 70.6]

90. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #89. Compliance shall be demonstrated by recording the number of deliveries of activated carbon, the number of deliveries of halide solution, and the tons of fly ash disposed of in the on-site landfill. The monthly mileage traveled shall be calculated based on the following equations:

Monthly Total Paved Miles Traveled = (AC * DPAC) + (HLD * DPHLD) + ((TASH/26) * DPASH)

Monthly Total Unpaved Miles Traveled = (AC * DUPAC) + (HLD * DUPHLD) + ((TASH/26) * DUPASH)

Where:
AC = monthly number of activated carbon deliveries
DPAC = round trip distance over paved roads for activated carbon deliveries
HLD = monthly number of halide solution deliveries
DPHLD = round trip distance over paved roads for halide solution deliveries
TASH = monthly tons of fly ash disposed in the on-site landfill
DPASH = round trip distance over paved roads for fly ash landfill disposal
DUPAC = round trip distance over unpaved roads for activated carbon deliveries
DUPHLD = round trip distance over unpaved roads for halide solution deliveries
DUPASH = round trip distance over unpaved roads for fly ash landfill disposal

The round trip mileage for activated carbon deliveries, halide solution deliveries, and for ash truck trips to the on-site landfill will be checked annually to determine the number of miles on paved and unpaved road. This check will be completed prior to the end of the first quarter of the year. The results will be recorded and used in the calculation for the remainder of the year unless an additional check is performed. The total miles traveled records shall be updated no later than the last day of the month following the month which the records represent. The records shall be kept on site, and shall be provided to Department personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

91. The permittee shall not operate the three Coal Yard Dozers more than a combined 12,000 hours per consecutive twelve (12) month period, and the water wagon shall not exceed 4,000 hours per consecutive twelve (12) month period. Hours of operation do not include time spent idling while stationary. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 70.6]

92. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #91. These records shall be updated no later than the last day of the month following the month which the records represent. The records shall be kept on site, and shall be provided to Department personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

93. The cat scraper shall not exceed 1,500 hours of operation per consecutive twelve (12) month period. Hours of operation do not include time spent idling while stationary. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 70.6]

94. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #93. These records shall be updated no later than the last day of the month following the month which the records represent. The records shall be kept on site, and shall be provided to Department personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

SN-04
Fly Ash Silos (2) with fabric filters

Source Description

The White Bluff Steam Electric Station is equipped with two (2) fly ash silos. Particulate emissions from the silos are controlled by fabric filters, SN-04, with a control efficiency of 99.9% for PM and 99.8% for PM_{10}.

Specific Conditions

95. The permittee shall not exceed the emission rates set forth in the following table. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
04 (M30-M31)	Fly Ash Silo with Fabric Filters	PM_{10}	0.1	0.1

96. The permittee shall not exceed the emission rates set forth in the following table. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
04 (M30-M31)	Fly Ash Silo with Fabric Filters	PM	0.1	0.1

97. The permittee shall not cause to be discharged to the atmosphere any emissions which exhibit an opacity greater than 20 percent. The opacity shall be measured in accordance with EPA Reference Method 9. [§19.503 of Regulation 19, and 40 CFR Part 52, Subpart E]

98. Plant personnel will perform a daily visual check, during daylight hours, to ensure the baghouse is functioning properly. Observations of the opacity from source SN-04 shall be conducted by personnel familiar with the permittee's visible emissions. These observations of opacity shall be conducted weekly and whenever visible emissions are detected during the daily visual checks. The permittee shall maintain personnel trained in (but not necessarily certified in) EPA Reference Method 9. If visible emissions are detected, the permittee shall identify the cause of the visible emissions and implement corrective action. The permittee shall maintain records which contain the following items in order to demonstrate compliance with this condition. These records shall be updated daily, kept on site, and made available to Department personnel upon request. The records shall be submitted to the Department in accordance with General Provision #7. [§19.705 of Regulation 19; 40 CFR Part 52, Subpart E; and 40 CFR Part 64]

a. The date and time of the opacity observation and/or visual check.

b. If any visible emissions were detected.

c. If any visible emissions were detected, the permittee shall document the opacity, the cause of the visible emissions, the corrective action taken, any necessary repairs, and if any visible emissions were detected following the repairs.

d. The name of the person conducting the opacity observation and/or visual check.

99. The permittee shall comply with the maintenance plan submitted to the Department for the fly ash silos (See Appendix C). Requirements include but are not limited to the following: [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

a. Check air leaks on pulsation system;

b. Check air operated valves;

c. Check piping and supports;

d. Check air cylinders;

e. Check baghouse doors and seals;

f. Check diffuser blower bearings for heat and vibration;

g. Check bags;

h. Check blower case for excessive heat buildup; and

i. Check inlet filter and change as needed.

100. The permittee shall conduct semi-annual maintenance inspections on the baghouses at SN-04. These inspections shall include checking all of the requirements listed in Specific Condition #99. The permittee shall maintain a record of these inspections. This record shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19; 40 CFR Part 52, Subpart E; and 40 CFR Part 64]

SN-07
Fuel Oil Storage Tank

Source Description

No. 2 fuel oil is stored in a storage tank (SN-07) on site. The tank has a capacity of 3,360,000 gallons or 80,000 barrels. The tank is cylindrical with a fixed roof.

Specific Conditions

101. The permittee shall not exceed the emission rates set forth in the following table. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
07	Fuel Oil Tank	VOC	1.9	2.4

102. The permittee shall not exceed the annual throughput limit of 112,000,000 gallons of No. 2 fuel oil at SN-07 during any consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

103. The permittee shall maintain records which demonstrate compliance with the limit set forth in Specific Condition #102. These records may be used by the Department for enforcement purposes. These records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. The twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

SN-14 through SN-16
Miscellaneous Storage Tanks

Source Description

The White Bluff Steam Electric Station has numerous storage tanks which store fuel oil and gasoline. SN-14 is a 4,000 gallon capacity No. 2 fuel oil storage tank, SN-15 is a 10,000 gallon No. 2 fuel oil storage tank, and SN-16 is a 4,000 gallon gasoline storage tank. Emissions from the tanks are volatile organic compounds (VOCs).

Specific Conditions

104. The permittee shall not exceed the emission rates set forth in the following table. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
14 (T25)	Miscellaneous Storage Tanks	VOC	0.1	0.1
15 (T26)	Miscellaneous Storage Tanks	VOC	0.1	0.1
16 (T32)	Miscellaneous Storage Tanks	VOC	18.9	0.1

105. The permittee shall store only distillate fuel oil No.2 in storage tanks SN-14 and SN-15. Supporting documentation shall be maintained on site to demonstrate compliance with this specific condition. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

106. The permittee shall store gasoline only in storage tank SN-16. Supporting documentation shall be maintained on site to demonstrate compliance with this specific condition. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

107. The permittee shall not exceed the annual throughput limit of 16,000 gallons of fuel at SN-14 during any consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

108. The permittee shall not exceed the annual throughput limit of 180,000 gallons of fuel at SN-15 during any consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

109. The permittee shall not exceed the annual throughput limit of 16,000 gallons of fuel at SN-16 during any consecutive twelve month period. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

110. The permittee shall maintain records which demonstrate compliance with the limits set forth in the Specific Conditions #105, 106, 107, 108 and 109. These records may be used by the Department for enforcement purposes. These records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. The twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

SN-17 and SN-18
Cooling Towers

Source Description

The White Bluff Steam Electric Station operates two (2) cooling towers for the purpose of waste heat dissipation. The cooling towers obtain makeup water from the Arkansas River and from the capture of site drainage.

Specific Conditions

111. The permittee shall not exceed the emission rates set forth in the following table. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
17 (X24)	Cooling Tower	PM_{10}	4.6	19.9
18 (X25)	Cooling Tower	PM_{10}	4.6	19.9

112. The permittee shall not exceed the emission rates set forth in the following table. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
17 (X24)	Cooling Tower	PM	4.6	19.9
18 (X25)	Cooling Tower	PM	4.6	19.9

113. The permittee shall not cause to be discharged to the atmosphere from these sources any emissions which exhibit an opacity greater than 20 percent. The opacity shall be measured in accordance with EPA Reference Method 9. [§19.503 of Regulation 19, and 40 CFR Part 52, Subpart E]

114. The permittee shall operate the cooling towers within the design specifications listed in Appendix C. Compliance with the design specifications may demonstrate compliance with the limit specified in Specific Condition #113. [§19.303 of Regulation 19, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

115. Total dissolved solids shall not exceed 2,800 parts per million. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

116. The permittee shall monitor the total dissolved solids weekly when the unit is operating to demonstrate compliance with Specific Condition #115. The permittee shall maintain

records that demonstrate compliance with this specific condition. These records shall be updated weekly, kept on site, and made available to Department personnel upon request. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

117. The circulating water flow for SN-17 and SN-18 shall not exceed 22,125 kgal/hr per tower. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

118. The permittee shall test the circulating water flow annually to demonstrate compliance with Specific Condition #117. The permittee shall maintain records that demonstrate compliance with this specific condition. These records shall be updated annually, kept on site, and made available to Department personnel upon request. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E]

SN-19
Coal Barging and Transfer

Source Description

This source consists of six transfer points and a paved/unpaved haul road for hauling the delivered coal via truck from the barge to the on-site coal storage piles. The six transfer points include: the conveyor feeder hopper which is filled from the barge with a large trackhoe, the drop point from the conveyor feed hopper to the first conveyor, the drop point from the first conveyor to the second conveyor, the truck feed hopper when filled via the second conveyor, filling of trucks from the truck feed hopper, and dumping the trucks onto the coal storage piles. The haul road consists of 1.9 miles of paved road and 0.25 miles of unpaved road. The unpaved road will be controlled with chemical suppressant and the paved road will be controlled by wetting and sweeping.

Specific Conditions

119. The permittee shall not exceed the emission rates set forth in the following table. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
19	Coal Barging and Transfer	PM_{10}	2.5	6.1

120. The permittee shall not exceed the emission rates set forth in the following table. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
19	Coal Barging and Transfer	PM	9.8	24.2

121. The permittee shall not operate in a manner such that emissions from the haul roads and transfer points (SN-19) would cause a nuisance off-site. Under normal conditions, off-site opacity less than or equal to 5% shall not be considered a nuisance. The permittee shall use water sprays, sweeping, or other techniques as necessary to control emissions. [§18.501 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

122. The permittee shall not exceed the annual throughput limit of 2,733,120 tons of coal at SN-19 during any consecutive twelve month period to demonstrate compliance with the annual emissions from the six transfer points. [§19.705 of Regulation 19, A.C.A. §8-3-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 70.6]

123. The permittee shall maintain purchase records which demonstrate compliance with Specific Condition #122. These records may be used by the Department for enforcement purposes. These records shall be updated on a monthly basis, shall be kept on site, and shall be provided to Department personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

124. The silt loading for the paved roads shall not exceed 0.99 g/m^2. Silt testing was conducted on October 5, 2005. Documentation of this test shall be maintained on site. [§19.705 of Regulation 19, A.C.A. §8-3-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 70.6]

125. The silt fraction for the unpaved roads shall not exceed 6.8%. Silt testing was conducted on September 22, 2005. Documentation of this test shall be maintained on site. [§19.705 of Regulation 19, A.C.A. §8-3-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 70.6]

126. The permittee shall not exceed 259,019.4 vehicle miles traveled per consecutive twelve (12) month period on the paved roads at SN-19. The permittee shall not exceed 34,081.5 vehicle miles traveled per consecutive twelve (12) month period on the unpaved roads at SN-19. This condition is necessary to demonstrate compliance with the haul road emission limits. [§19.705 of Regulation 19, A.C.A. §8-3-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 70.6]

127. The permittee shall maintain monthly records to demonstrate compliance with Specific Condition #126. Compliance shall be demonstrated by recording the round trips traveled by the dust control equipment (water trucks, sweepers, etc.), recording the tons of barge delivered coal unloaded, and calculating the vehicle miles traveled based on the following equations:

$$\text{Monthly Total Paved Miles Traveled} = \left[\left(\text{Control Equipment Round Trips}\right) + \left(\frac{\text{Monthly tons unloaded}}{\text{26 tons per round trip}}\right)\right] \times \left(\text{" Miles Paved" per round trip}\right)$$

$$\text{Monthly Total Unpaved Miles Traveled} = \left[\left(\text{Control Equipment Round Trips}\right) + \left(\frac{\text{Monthly tons unloaded}}{\text{26 tons per round trip}}\right)\right] \times \left(\text{" Miles Unpaved" per round trip}\right)$$

Haul truck weight shall typically be 40 tons loaded and 14 tons unloaded, and generally only full haul trucks shall be used to transport coal. The round trip mileage will be 3.8 miles paved and 0.5 miles unpaved unless an alternate shorter route is implemented. If an alternate route is to be used the round trip mileage will be checked and submitted to the Department. The new mileage can be used in the calculations immediately upon approval by the Department. The total miles traveled records shall be updated no later than the last day of the month following the month which the records represent. The records shall be kept on site, and shall be provided to Department personnel upon request.

A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision #7. Construction of an alternate haul road shall comply with Plantwide Conditions #1 and #2. [§19.705 of Regulation 19 and 40 CFR Part 52, Subpart E]

128. The permittee shall comply with the Haul Road Dust Control Plan for the Barge Unloading Operation (Appendix D). This plan shall be kept on site, and shall be provided to Department personnel upon request. The paved roads shall be controlled by wetting and sweeping. The unpaved roads shall be controlled by the application of a chemical dust suppressant. Control shall be required more frequently as necessary to comply with Specific Condition #121. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

129. The chemical suppressant used on the unpaved roads at SN-19 shall not contain any VOCs. The permittee shall maintain the MSDS on site to demonstrate compliance with this specific condition. [§19.705 of Regulation 19, A.C.A. §8-3-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 70.6]

130. The chemical suppressant used on the unpaved roads at SN-19 shall not contain any HAPs. The permittee shall maintain the MSDS on site to demonstrate compliance with this specific condition. [§18.1004 of Regulation 18 and A.C.A. §8-3-203 as referenced by §8-4-304 and §8-4-311]

SN-20
Degreasing Operations

Source Description

This source consists of eight degreasers with a total capacity of 605 gallons. Four (4) of the degreasers are used during outage periods only.

Specific Conditions

131. The permittee shall not exceed the emission rates set forth in the following table. [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
20	Degreasing Operations	VOC	6.8	13.6

132. The VOC content of the solvent used at SN-20 shall not exceed 6.8 pounds of VOC per gallon of solvent. Material Safety Data Sheets shall be maintained on site to demonstrate compliance with this specific condition. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

133. The throughput of SN-20 shall not exceed 4,000 gallons of solvent per consecutive twelve-month period. [Regulation 19, §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

134. Monthly records shall be maintained to demonstrate compliance with Specific Condition #133. These records shall be updated no later than the last day of the month following the month which the records represent. A twelve month rolling total and each individual month's data shall be maintained on site, made available to Department personnel upon request, and submitted in accordance with General Provision #7. [Regulation 19, §19.705, and 40 CFR Part 52, Subpart E]

SN-21 and SN-22
Emergency Diesel Generator and Emergency Diesel Fire Pump

Source Description

An 8.22 MMBtu/hr emergency diesel generator and a 323 HP Cummins, Model CFP9E-F30 diesel fire pump are used for emergency situation.

Specific Conditions

135. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by purchasing a NSPS certified engine and by Specific Condition #138 . [Regulation 19, §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
21	Emergency Diesel Generator	PM_{10}	0.5	0.6
		SO_2	4.2	4.5
		VOC	0.8	0.8
		CO	7.0	7.6
		NO_x	26.3	28.5
22	Emergency Diesel Fire Pump	PM_{10}	0.1	0.2
		SO_2	0.7	1.0
		VOC	0.11	0.2
		CO	1.1	1.6
		NO_x	1.7	2.6

136. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by purchasing a NSPS certified engine and by Specific Condition #138. [Regulation 18, §18.801, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Description	Pollutant	lb/hr	tpy
21	Emergency Diesel Generator	PM	0.6	0.7
		Acetaldehyde	0.000207	0.00022
		Acrolein	0.000065	0.00007

		Benzene	0.006379	0.0069
		Formaldehyde	0.000649	0.0007
22	Fire Pump Emergency Diesel Generator	PM	0.10	0.20
		Acetaldehyde	0.001841	0.00276
		Acrolein	0.000222	0.000333
		Benzene	0.002239	0.0034
		Formaldehyde	0.002832	0.004248

137. The permittee shall not exceed 20% opacity from SN-21 and SN-22 as measured by EPA Reference Method 9. Compliance with this Specific Condition shall be demonstrated by compliance with Specific Condition #140. [Regulation 19, §19.503, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

138. The permittee shall not operate the emergency diesel generator (SN-21) in excess of 2,160 hours and the fire pump emergency diesel generator (SN-22) in excess of 3,000 hours during any consecutive twelve-month period. [Regulation 19, §19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

139. The permittee shall maintain records of the hours of operation of SN-21 and SN-22 which demonstrate compliance with limits set in Specific Condition # 138. These records shall be updated on a monthly basis, and shall be provided to Department personnel upon request. An annual total and each individual month's data shall be submitted in accordance with General Provision #7. [Regulation 19, §19.705 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

140. Daily visible emission observations shall be used as a method of compliance verification for the opacity limits assigned for SN-21 and SN-22 while the emergency diesel generator is in operation for more than 24 consecutive hours. The observations shall be conducted by someone familiar with EPA Reference Method 9. If during the observations, visible emissions are detected which appear to be in excess of the permitted opacity limit, the permittee shall:

    a. Take immediate action to identify the cause of the visible emissions,
    b. Implement corrective action, and
    c. If excessive visible emissions are still detected, an opacity reading shall be conducted in accordance with EPA Reference Method 9 for point sources and in accordance with EPA Method 22 for non-point sources. This reading shall be conducted by a person trained and certified in the reference method. If the opacity reading exceeds the permitted limit, further corrective measures shall be taken.

d. If no excessive visible emissions are detected, the incident shall be noted in the records as described below.
e. The permittee shall maintain records related to all visible emission observations and Method 9 readings. These records shall be updated on an as-performed basis. These records shall be kept on site and made available to Department personnel upon request. These records shall contain:
f. The time and date of each observation/reading,
g. Any observance of visible emissions appearing to be above permitted limits or any Method 9 reading which indicates exceedance,
h. The cause of any observed exceedance of opacity limits, corrective actions taken, and results of the reassessment, and
i. The name of the person conducting the observation/reading.

141. The permittee shall conduct an opacity reading using Method 9 at SN-21 and SN-22 at least once a year when it is operating. The permittee shall maintain records which demonstrate compliance with the opacity limit. These records may be used by the Department for enforcement purposes. The records shall be provided to the Department personnel upon request. [Regulation 19, §19.503, §19.705 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

142. SN-21 is subject to 40 CFR, Part 63, Subpart ZZZZ, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.* This engine is subject to the requirements in 40 CFR 63.6640(f). No other requirements apply. [Regulation 19 §19.304 and 40 CFR Part 63.6640(f)]

a. 63.6640(f)(2) If you own or operate an emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed prior to June 12, 2006, you must operate the engine according to the conditions described in paragraphs (f)(2)(i) through (iii) of this section. If you do not operate the engine according to the requirements in paragraphs (f)(2)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.
   i. (i) There is no time limit on the use of emergency stationary RICE in emergency situations.
   ii. (ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance.
   iii. (iii) You may operate your emergency stationary RICE for an additional 50 hours per year in non-emergency situations. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

143. SN-22 is a new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions. SN-22 must meet the requirements of 40 CFR 63 Subpart ZZZZ by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines. No further requirements apply for this engine under this part. [Regulation No. 19 §19.304 and 40 CFR 63.6590(c)(6)]

144. Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 of 40 CFR 6o Subpart IIII, for all pollutants. Compliance is determined by purchase of a certified engine. [Regulation No. 19 §19.304 and 40 CFR 60.4205(c)]

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
225≤KW<450 (300≤HP<600)	2009+	4.0 (3.0)		0.20 (0.15)

145. Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) below for nonroad diesel fuel. [Regulation No. 19 §19.304 and 40 CFR 60.4207(b)]

80.510(b) *Beginning June 1, 2010*. Except as otherwise specifically provided in this subpart, all NR and LM diesel fuel is subject to the following per-gallon standards:

(1) Sulfur content.

(i) 15 ppm maximum for NR diesel fuel.

(ii) 500 ppm maximum for LM diesel fuel.

(2) Cetane index or aromatic content, as follows:

(i) A minimum cetane index of 40; or

(ii) A maximum aromatic content of 35 volume percent.

146. If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine. [Regulation No. 19 §19.304 and 40 CFR 60.4209(a)]

147. Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing. [Regulation No. 19 §19.304 and 40 CFR 60.4210(f)]

148. If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications. [Regulation No. 19 §19.304 and 40 CFR 60.4211(c)]

149. Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited. [Regulation No. 19 §19.304 and 40 CFR 60.4211(e)]

150. If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time. [Regulation No. 19 §19.304 and 40 CFR 60.4214(b)]

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

SECTION V: COMPLIANCE PLAN AND SCHEDULE

Entergy Arkansas, Inc. (White Bluff Plant) will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Regulation 19 §19.704, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Regulation 19 §19.410(B) and 40 CFR Part 52, Subpart E]

3. The permittee must test any equipment scheduled for testing, unless otherwise stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) business days in advance of such test. The permittee shall submit the compliance test results to the Department within thirty (30) calendar days after completing the testing. [Regulation 19 §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

4. The permittee must provide:

    a. Sampling ports adequate for applicable test methods;
    b. Safe sampling platforms;
    c. Safe access to sampling platforms; and
    d. Utilities for sampling and testing equipment.

    [Regulation 19 §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [Regulation 19 §19.303 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

6. This permit subsumes and incorporates all previously issued air permits for this facility. [Regulation 26 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

7. Dust suppression activities should be conducted in a manner and at a rate of application that will not cause runoff from the area being applied. Best Management Practices (40

CFR §122.44(k)) should be used around streams and waterbodies to prevent the dust suppression agent from entering Waters of the State. Except for potable water, no agent shall be applied within 100 feet of wetlands, lakes, ponds, springs, streams, or sinkholes. Failure to meet this condition may require the permittee to obtain a National Pollutant Discharge Elimination System (NPDES) permit in accordance with 40 CFR §122.1(b). [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Acid Rain (Title IV)

8. The Director prohibits the permittee to cause any emissions exceeding any allowances the source lawfully holds under Title IV of the Act or the regulations promulgated under the Act. No permit revision is required for increases in emissions allowed by allowances acquired pursuant to the acid rain program, if such increases do not require a permit revision under any other applicable requirement. This permit establishes no limit on the number of allowances held by the permittee. However, the source may not use allowances as a defense for noncompliance with any other applicable requirement of this permit or the Act. The permittee will account for any such allowance according to the procedures established in regulations promulgated under Title IV of the Act. A copy of the facility's Acid Rain Permit is attached in an appendix to this Title V permit. [Regulation 26 §26.701 and 40 CFR 70.6(a)(4)]

CAIR

9. The permittee shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of 40 CFR part 96. The permittee shall comply with the NOx emission requirements established under CAIR. The Permittee shall report and maintain the records required by subpart HHHH of 40 CFR part 96. A copy of the CAIR permit is attached to this Title V permit. [Regulation 19 §19.1401 and 40 CFR Part 52, Subpart E]

Title VI Provisions

10. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 CFR Part 82, Subpart E]

    a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to §82.106.
    b. The placement of the required warning statement must comply with the requirements pursuant to §82.108.
    c. The form of the label bearing the required warning must comply with the requirements pursuant to §82.110.
    d. No person may modify, remove, or interfere with the required warning statement except as described in §82.112.

11. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 CFR Part 82, Subpart F]

    a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.
    b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.
    c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.
    d. Persons disposing of small appliances, MVACs, and MVAC like appliances must comply with record keeping requirements pursuant to §82.166. ("MVAC like appliance" as defined at §82.152)
    e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to §82.156.
    f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

12. If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 CFR Part 82, Subpart A, Production and Consumption Controls.

13. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

    The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC 22 refrigerant.

14. The permittee can switch from any ozone depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR Part 82, Subpart G.

15. The annual throughput of coal at the facility shall not exceed 9.2 million tons of coal per any consecutive twelve month period. [§ 19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]

16. The permittee shall maintain records which demonstrate compliance with the limit set in Plantwide Condition #15. These records shall be updated on a monthly basis, shall be

kept on site, shall be provided to Department personnel upon request, and shall be submitted in accordance with General Provision #7. [§19.705 of Regulation 19, and 40 CFR Part 52, Subpart E)

SECTION VII: INSIGNIFICANT ACTIVITIES

The following sources are insignificant activities. Any activity that has a state or federal applicable requirement shall be considered a significant activity even if this activity meets the criteria of §26.304 of Regulation 26 or listed in the table below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated October 20, 2009 and September 21, 2011.

Description	Category
Microwave Tower Propane Generators (C6a and C6b), Kerosene Fired Space Heaters (C7)	A-1
28 – Storage tanks less than 250 gallons storing organic liquids having a true vapor pressure less than or equal to 3.5 psia. (T6 – T10, T15 – T19, T96, T97, T98, T99(2), T100(2), T114(4), T123, T124(2), T125(2), T126(2))	A-2
29 – Storage tanks less than 10,000 gallons storing organic liquids having a true vapor pressure less than or equal to 0.5 psia. (T4, T5(2), T13, T14(2), T21, T22(3), T24, T27, T29, T30, T31, T94, T95, T113, T115(3), T116(3), T120, T121, T122(2), T127)	A-3
Emissions from laboratory equipment/vents. (T93)	A-5
Other activities for which the facility demonstrates that no enforceable permit conditions are necessary to insure compliance with any applicable law or regulation provided that the emissions are less than 5 tpy of any pollutant regulated under this regulation or less than 1 tpy of a single HAP or 2.5 tpy of any combination of HAPs. Unit 1 Turbine Lube Oil Storage Tank (T2), Unit 1 Turbine Lube Oil Reservoir (T3), Unit 2 Lube Oil Storage Tank (T11), Unit 2 Turbine Lube Oil Reservoir (T12), Four Unit 1 Glycol Air Preheater Expansion Tanks (T51), Two Unit 2 Glycol Mixing Tanks (T53), Ethylene Glycol Storage Tank (T54), Unit 1 Glycol Mixing Tank (T57), Unit 1 Hydrazine Mixing Tank (T58), Hydrazine Solution Bulk Containers (T59), EHC Fluid Storage (T71), Welding Area – Machine Shop (X10), Welding Area – Bowl Mill Shop (X11), Unleaded Gasoline Dispensing Station (X15), Diesel Dispensing Station (X16), Indoor Enclosed Sandblast Unit (X22), Unit 1 ESP Transformer/Rectifiers (X31), Unit 2 ESP Transformer/Rectifier (X32), Spare ESP Transformer/Rectifier (X33), Transformers (X34), Switchyard Transformers & Oil Circuit Breakers (X35), Aerosol Lubricant (X55), and Aerosol Degreaser (X56), 2 - Economizer Ash Silos (M60 & M61), 2 - Activated Carbon Silos	A-13
18 - AC Chiller – Pressure Tanks (X36-X54), 2 - Aqueous Halide Storage Units	No Emissions

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 CFR 70.6(b)(2)]

2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 CFR 70.6(a)(2) and Regulation 26 §26.701(B)]

3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due. [Regulation 26 §26.406]

4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, et seq. (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 CFR 70.6(a)(1)(ii) and Regulation 26 §26.701(A)(2)]

5. The permittee must maintain the following records of monitoring information as required by this permit.

   a. The date, place as defined in this permit, and time of sampling or measurements;
   b. The date(s) analyses performed;
   c. The company or entity performing the analyses;
   d. The analytical techniques or methods used;
   e. The results of such analyses; and
   f. The operating conditions existing at the time of sampling or measurement.

   [40 CFR 70.6(a)(3)(ii)(A) and Regulation 26 §26.701(C)(2)]

6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 CFR 70.6(a)(3)(ii)(B) and Regulation 26 §26.701(C)(2)(b)]

7. The permittee must submit reports of all required monitoring every six (6) months. If the permit establishes no other reporting period, the reporting period shall end on the last day of the month six months after the issuance of the initial Title V permit and every six months thereafter. The report is due on the first day of the second month after the end of the reporting period. The first report due after issuance of the initial Title V permit shall contain six months of data and each report thereafter shall contain 12 months of data. The report shall contain data for all monitoring requirements in effect during the reporting period. If a monitoring requirement is not in effect for the entire reporting period, only those months of data in which the monitoring requirement was in effect are required to be reported. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Regulation No. 26, §26.2 must certify all required reports. The permittee will send the reports to the address below:

   Arkansas Department of Environmental Quality
   Air Division
   ATTN: Compliance Inspector Supervisor
   5301 Northshore Drive
   North Little Rock, AR 72118-5317

   [40 CFR 70.6(a)(3)(iii)(A) and Regulation 26 §26.701(C)(3)(a)]

8. The permittee shall report to the Department all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.

   a. For all upset conditions (as defined in Regulation19, § 19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:

      i. The facility name and location;
      ii. The process unit or emission source deviating from the permit limit;
      iii. The permit limit, including the identification of pollutants, from which deviation occurs;
      iv. The date and time the deviation started;
      v. The duration of the deviation;
      vi. The average emissions during the deviation;
      vii. The probable cause of such deviations;

viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future; and

ix. The name of the person submitting the report.

The permittee shall make a full report in writing to the Department within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.

[Regulation 19 §19.601 and §19.602, Regulation 26 §26.701(C)(3)(b), and 40 CFR 70.6(a)(3)(iii)(B)]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 CFR 70.6(a)(5), Regulation 26 §26.701(E), and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. §7401, et seq. and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 CFR 70.6(a)(6)(i) and Regulation 26 §26.701(F)(1)]

11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 CFR 70.6(a)(6)(ii) and Regulation 26 §26.701(F)(2)]

12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR 70.6(a)(6)(iii) and Regulation 26 §26.701(F)(3)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR 70.6(a)(6)(iv) and Regulation 26 §26.701(F)(4)]

14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Department may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 CFR 70.6(a)(6)(v) and Regulation 26 §26.701(F)(5)]

15. The permittee must pay all permit fees in accordance with the procedures established in Regulation 9. [40 CFR 70.6(a)(7) and Regulation 26 §26.701(G)]

16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 CFR 70.6(a)(8) and Regulation 26 §26.701(H)]

17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 CFR 70.6(a)(9)(i) and Regulation 26 §26.701(I)(1)]

18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 CFR 70.6(b) and Regulation 26 §26.702(A) and (B)]

19. Any document (including reports) required by this permit must contain a certification by a responsible official as defined in Regulation 26, §26.2. [40 CFR 70.6(c)(1) and Regulation 26 §26.703(A)]

20. The permittee must allow an authorized representative of the Department, upon presentation of credentials, to perform the following: [40 CFR 70.6(c)(2) and Regulation 26 §26.703(B)]

    a. Enter upon the permittee's premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
    b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;

c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually. If the permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due on the first day of the second month after the end of the reporting period. The permittee must also submit the compliance certification to the Administrator as well as to the Department. All compliance certifications required by this permit must include the following: [40 CFR 70.6(c)(5) and Regulation 26 §26.703(E)(3)]

    a. The identification of each term or condition of the permit that is the basis of the certification;
    b. The compliance status;
    c. Whether compliance was continuous or intermittent;
    d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and
    e. Such other facts as the Department may require elsewhere in this permit or by §114(a)(3) and §504(b) of the Act.

22. Nothing in this permit will alter or affect the following: [Regulation 26 §26.704(C)]

    a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
    b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
    c. The applicable requirements of the acid rain program, consistent with §408(a) of the Act; or
    d. The ability of EPA to obtain information from a source pursuant to §114 of the Act.

23. This permit authorizes only those pollutant emitting activities addressed in this permit. [A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

24. The permittee may request in writing and at least 15 days in advance of the deadline, an extension to any testing, compliance or other dates in this permit. No such extensions are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion in the following circumstances:

a. Such an extension does not violate a federal requirement;
b. The permittee demonstrates the need for the extension; and
c. The permittee documents that all reasonable measures have been taken to meet the current deadline and documents reasons it cannot be met.

[Regulation 18 §18.314(A), Regulation 19 §19.416(A), Regulation 26 §26.1013(A), A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

25. The permittee may request in writing and at least 30 days in advance, temporary emissions and/or testing that would otherwise exceed an emission rate, throughput requirement, or other limit in this permit. No such activities are authorized until the permittee receives written Department approval. Any such emissions shall be included in the facility's total emissions and reported as such. The Department may grant such a request, at its discretion under the following conditions:

a. Such a request does not violate a federal requirement;
b. Such a request is temporary in nature;
c. Such a request will not result in a condition of air pollution;
d. The request contains such information necessary for the Department to evaluate the request, including but not limited to, quantification of such emissions and the date/time such emission will occur;
e. Such a request will result in increased emissions less than five tons of any individual criteria pollutant, one ton of any single HAP and 2.5 tons of total HAPs; and
f. The permittee maintains records of the dates and results of such temporary emissions/testing.

[Regulation 18 §18.314(B), Regulation 19 §19.416(B), Regulation 26 §26.1013(B), A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

26. The permittee may request in writing and at least 30 days in advance, an alternative to the specified monitoring in this permit. No such alternatives are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion under the following conditions:

a. The request does not violate a federal requirement;
b. The request provides an equivalent or greater degree of actual monitoring to the current requirements; and
c. Any such request, if approved, is incorporated in the next permit modification application by the permittee.

[Regulation 18 §18.314(C), Regulation 19 §19.416(C), Regulation 26 §26.1013(C), A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

Appendix A

40 CFR Part 60, Subpart D – *Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971*

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Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Browse Previous | Browse Next

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators

Source: 72 FR 32717, June 13, 2007, unless otherwise noted.

§ 60.40 Applicability and designation of affected facility.

(a) The affected facilities to which the provisions of this subpart apply are:

(1) Each fossil-fuel-fired steam generating unit of more than 73 megawatts (MW) heat input rate (250 million British thermal units per hour (MMBtu/hr)).

(2) Each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 MW (250 MMBtu/hr).

(b) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

(c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(d) The requirements of §§60.44 (a)(4), (a)(5), (b) and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.

(e) Any facility subject to either subpart Da or KKKK of this part is not subject to this subpart.

[72 FR 32717, June 13, 2007, as amended at 77 FR 9447, Feb. 16, 2012]

§ 60.41 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, and in subpart A of this part.

Boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference, see §60.17).

Coal refuse means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

Fossil fuel and wood residue-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.

Fossil-fuel-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, *natural gas* contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Wood residue means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.

[72 FR 32717, June 13, 2007, as amended at 77 FR 9447, Feb. 16, 2012]

§ 60.42 Standard for particulate matter (PM).

(a) Except as provided under paragraphs (b), (c), (d), and (e) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:

(1) Contain PM in excess of 43 nanograms per joule (ng/J) heat input (0.10 lb/MMBtu) derived from fossil fuel or fossil fuel and wood residue.

(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.

(b)(1) On or after December 28, 1979, no owner or operator shall cause to be discharged into the atmosphere from the Southwestern Public Service Company's Harrington Station #1, in Amarillo, TX, any gases which exhibit greater than 35 percent opacity, except that a maximum or 42 percent opacity shall be permitted for not more than 6 minutes in any hour.

(2) Interstate Power Company shall not cause to be discharged into the atmosphere from its Lansing Station Unit No. 4 in Lansing, IA, any gases which exhibit greater than 32 percent opacity, except that a maximum of 39 percent opacity shall be permitted for not more than six minutes in any hour.

(c) As an alternate to meeting the requirements of paragraph (a) of this section, an owner or operator that elects to install, calibrate, maintain, and operate a continuous emissions monitoring systems (CEMS) for measuring PM emissions can petition the Administrator (in writing) to comply with §60.42Da (a) of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in §60.42Da(a) of subpart Da of this part.

(d) An owner or operator of an affected facility that combusts only natural gas is exempt from the PM and opacity standards specified in paragraph (a) of this section.

(e) An owner or operator of an affected facility that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2 or PM is exempt from the PM standards specified in paragraph (a) of this section.

[60 FR 65415, Dec. 19, 1995, as amended at 76 FR 3522, Jan. 20, 2011; 74 FR 5077, Jan. 28, 2009; 77 FR 9447, Feb. 16, 2012]

§ 60.43 Standard for sulfur dioxide (SO_2).

(a) Except as provided under paragraph (d) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of:

(1) 340 ng/J heat input (0.80 lb/MMBtu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.

(2) 520 ng/J heat input (1.2 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in paragraph (e) of this section.

(b) Except as provided under paragraph (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO_2} = \frac{y\,(340) + z\,(520)}{(y + z)}$$

Where:

$PS_{SO}2$= Prorated standard for S_{O2} when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels or from all fossil fuels and wood residue fired;

y = Percentage of total heat input derived from liquid fossil fuel; and

z = Percentage of total heat input derived from solid fossil fuel.

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

(d) As an alternate to meeting the requirements of paragraphs (a) and (b) of this section, an owner or operator can petition the Administrator (in writing) to comply with §60.43Da(i)(3) of subpart Da of this part or comply with §60.42b(k)(4) of subpart Db of this part, as applicable to the affected source. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in §60.43Da(i)(3) of subpart Da of this part or §60.42b(k)(4) of subpart Db of this part, as applicable to the affected source.

(e) Units 1 and 2 (as defined in appendix G of this part) at the Newton Power Station owned or operated by the Central Illinois Public Service Company will be in compliance with paragraph (a)(2) of this section if Unit 1 and Unit 2 individually comply with paragraph (a)(2) of this section or if the combined emission rate from Units 1 and 2 does not exceed 470 ng/J (1.1 lb/MMBtu) combined heat input to Units 1 and 2.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5077, Jan. 28, 2009]

§ 60.44 Standard for nitrogen oxides (NOX).

(a) Except as provided under paragraph (e) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NO_X, expressed as NO_2 in excess of:

(1) 86 ng/J heat input (0.20 lb/MMBtu) derived from gaseous fossil fuel.

(2) 129 ng/J heat input (0.30 lb/MMBtu) derived from liquid fossil fuel, liquid fossil fuel and wood residue,

or gaseous fossil fuel and wood residue.

(3) 300 ng/J heat input (0.70 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

(4) 260 ng/J heat input (0.60 lb MMBtu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).

(5) 340 ng/J heat input (0.80 lb MMBtu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.

(b) Except as provided under paragraphs (c), (d), and (e) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NO_x} = \frac{w\,(260) + x\,(86) + y\,(130) + z\,(300)}{(w + x + y + z)}$$

Where:

PS_{NOX}= Prorated standard for NO_X when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w = Percentage of total heat input derived from lignite;

x = Percentage of total heat input derived from gaseous fossil fuel;

y = Percentage of total heat input derived from liquid fossil fuel; and

z = Percentage of total heat input derived from solid fossil fuel (except lignite).

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for NO_X does not apply.

(d) Except as provided under paragraph (e) of this section, cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.

(e) As an alternate to meeting the requirements of paragraphs (a), (b), and (d) of this section, an owner or operator can petition the Administrator (in writing) to comply with §60.44Da(e)(3) of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in §60.44Da(e)(3) of subpart Da of this part.

§ 60.45 Emissions and fuel monitoring.

(a) Each owner or operator of an affected facility subject to the applicable emissions standard shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a continuous emissions monitoring system (CEMS) for measuring SO_2 emissions, NO_X emissions, and either oxygen (O_2) or carbon dioxide (CO_2) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS and COMS requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil-fuel-fired steam generator that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use

post-combustion technology to reduce emissions of SO_2 or PM, COMS for measuring the opacity of emissions and CEMS for measuring SO_2 emissions are not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis or fuel receipts.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring SO_2 emissions is not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis.

(3) Notwithstanding §60.13(b), installation of a CEMS for NO_X may be delayed until after the initial performance tests under §60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of NO_X are less than 70 percent of the applicable standards in §60.44, a CEMS for measuring NO_X emissions is not required. If the initial performance test results show that NO_X emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for NO_X within one year after the date of the initial performance tests under §60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator is not required to and elects not to install any CEMS for either SO_2 or NO_X, a CEMS for measuring either O_2 or CO_2 is not required.

(5) For affected facilities using a PM CEMS, a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in §60.48Da of this part, or an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section §60.48Da of this part a COMS is not required.

(6) A COMS for measuring the opacity of emissions is not required for an affected facility that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (b)(6)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each boiler operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each boiler operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (b)(6) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(7) An owner or operator of an affected facility subject to an opacity standard under §60.42 that elects to not use a COMS because the affected facility burns only fuels as specified under paragraph (b)(1) of this section, monitors PM emissions as specified under paragraph (b)(5) of this section, or monitors CO emissions as specified under paragraph (b)(6) of this section, shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.42 by April 29, 2011 or within 45 days after stopping use of an existing COMS, whichever is later, and shall comply with either paragraph (b)(7)(i), (b)(7)(ii), or (b)(7)(iii) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation. The permitting authority may exempt owners or operators of affected facilities burning only natural gas from the opacity monitoring requirements.

(i) Except as provided in paragraph (b)(7)(ii) or (b)(7)(iii) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (b)(7) of this section according to the applicable schedule in paragraphs (b)(7)(i)(A) through (b)(7)(i)(D) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(A) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(C) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(D) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(ii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 of this part performance test, elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in paragraphs (b)(7)(ii)(A) and (B) of this section.

(A) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A–7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (i.e., 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (i.e., 90 seconds) or conduct a new Method 9 of appendix A–4 of this part performance test using the procedures in paragraph (b)(7) of this section within 45 calendar days according to the requirements in §60.46(b)(3).

(B) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(iii) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (b)(7)(ii) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(8) A COMS for measuring the opacity of emissions is not required for an affected facility at which the owner or operator installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

(c) For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO_2 and NO_X continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in §60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NO_X the span value shall be determined using one of the following procedures:

(i) Except as provided under paragraph (c)(3)(ii) of this section, SO_2 and NO_X span values shall be determined as follows:

Fossil fuel	In parts per million	
	Span value for SO_2	**Span value for NO_X**
Gas	([1])	500.
Liquid	1,000	500.
Solid	1,500	1,000.
Combinations	1,000y + 1,500z	500 (x + y) + 1,000z.

[1]Not applicable.

Where:

x = Fraction of total heat input derived from gaseous fossil fuel;

y = Fraction of total heat input derived from liquid fossil fuel; and

z = Fraction of total heat input derived from solid fossil fuel.

(ii) As an alternative to meeting the requirements of paragraph (c)(3)(i) of this section, the owner or operator of an affected facility may elect to use the SO_2 and NO_X span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

(4) All span values computed under paragraph (c)(3)(i) of this section for burning combinations of fossil

fuels shall be rounded to the nearest 500 ppm. Span values that are computed under paragraph (c)(3)(ii) of this section shall be rounded off according to the applicable procedures in section 2 of appendix A to part 75 of this chapter.

(5) For a fossil-fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all CEMS shall be subject to the Administrator's approval.

(d) [Reserved]

(e) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(1) When a CEMS for measuring O_2 is selected, the measurement of the pollutant concentration and O_2 concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(2) When a CEMS for measuring CO_2 is selected, the measurement of the pollutant concentration and CO_2 concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

(f) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(1) E = pollutant emissions, ng/J (lb/MMBtu).

(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^4 M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO_2 and 46.01 for NO_X.

(3) $\%O_2$, $\%CO_2$ = O_2 or CO_2 volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(4) F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = $2,723 \times 10^{-17}$ dscm/J (10,140 dscf/MMBtu) and F_c = 0.532×10^{-17} scm CO_2/J (1,980 scf CO_2/MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = 2.637×10^{-7} dscm/J (9,820 dscf/MMBtu) and F_c = 0.486×10^{-7} scm CO_2/J (1,810 scf CO_2/MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476 × 10^{-7}dscm/J (9,220 dscf/MMBtu) and F_c= 0.384 × 10^{-7}scm CO_2/J (1,430 scf CO_2/MMBtu).

(iv) For gaseous fossil fuels, F = 2.347 × 10^{-7}dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, F_c= 0.279 × 10^{-7}scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322 × 10^{-7}scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338 × 10^{-7}scm CO_2/J (1,260 scf CO_2/MMBtu) for butane.

(v) For bark F = 2.589 × 10^{-7}dscm/J (9,640 dscf/MMBtu) and F_c= 0.500 × 10^{-7}scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark F = 2.492 × 10^{-7}dscm/J (9,280 dscf/MMBtu) and F_c= 0.494 × 10^{-7}scm CO_2/J (1,860 scf CO_2/MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see §60.17), F = 2.659 × 10^{-7}dscm/J (9,900 dscf/MMBtu) and F_c= 0.516 × 10^{-7}scm CO_2/J (1,920 scf CO_2/MMBtu).

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or $F_c$factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6}\frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0\times10^{-5}(\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6}\frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321\times10^{3}\ (\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2 (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see §60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see §60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

Where:

X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);

F_i or $(F_c)_i$= Applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and

n = Number of fuels being burned in combination.

(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) *Opacity* . Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(i) For sources subject to the opacity standard of §60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.

(ii) For sources subject to the opacity standard of §60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average per hour of up to 39 percent opacity need not be reported.

(2) *Sulfur dioxide.* Excess emissions for affected facilities are defined as:

(i) For affected facilities electing not to comply with §60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43; or

(ii) For affected facilities electing to comply with §60.43(d), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43. Facilities complying with the 30-day SO_2 standard shall use the most current associated SO_2 compliance and monitoring requirements in §§60.48Da and 60.49Da of subpart Da of this part or §§60.45b and 60.47b of subpart Db of this part, as applicable.

(3) *Nitrogen oxides.* Excess emissions for affected facilities using a CEMS for measuring NO_X are defined as:

(i) For affected facilities electing not to comply with §60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44; or

(ii) For affected facilities electing to comply with §60.44(e), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO_X as measured by a CEMS exceed the applicable standard in §60.44. Facilities complying with the 30-day NO_X standard shall use the most current associated NO_X compliance and monitoring requirements in §§60.48Da and 60.49Da of subpart Da of this part.

(4) *Particulate matter*. Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all

operating one-hour periods) exceed the applicable standards in §60.42. Affected facilities using PM CEMS must follow the most current applicable compliance and monitoring provisions in §§60.48Da and 60.49Da of subpart Da of this part.

(h) The owner or operator of an affected facility subject to the opacity limits in §60.42 that elects to monitor emissions according to the requirements in §60.45(b)(7) shall maintain records according to the requirements specified in paragraphs (h)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5077, Jan. 28, 2009; 76 FR 3522, Jan. 20, 2011; 77 FR 9447, Feb. 16, 2012]

§ 60.46 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, and subsequent performance tests as requested by the EPA Administrator, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in paragraph (d) of this section.

(b) The owner or operator shall determine compliance with the PM, SO_2, and NO_X standards in §§60.42, 60.43, and 60.44 as follows:

(1) The emission rate (E) of PM, SO_2, or NO_X shall be computed for each run using the following equation:

$$E = CF_d \left(\frac{20.9}{(20.9 - \%O_2)} \right)$$

Where:

E = Emission rate of pollutant, ng/J (1b/million Btu);

C = Concentration of pollutant, ng/dscm (1b/dscf);

$\%O_2$= O_2concentration, percent dry basis; and

F_d= Factor as determined from Method 19 of appendix A of this part.

(2) Method 5 of appendix A of this part shall be used to determine the PM concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B of appendix A of this part shall be used to determine the PM concentration (C) after FGD systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160±14 ℃ (320±25 ℉).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2concentration ($\%O_2$). The O_2sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2concentration for the run shall be the arithmetic mean of the sample O_2concentrations at all traverse points.

(iii) If the particulate run has more than 12 traverse points, the O_2traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2traverse points.

(3) Method 9 of appendix A of this part and the procedures in §60.11 shall be used to determine opacity.

(4) Method 6 of appendix A of this part shall be used to determine the SO_2concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2concentration ($\%O_2$). The O_2sample shall be taken simultaneously with, and at the same point as, the SO_2sample. The SO_2emission rate shall be computed for each pair of $SO_2$and O_2samples. The SO_2emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 of appendix A of this part shall be used to determine the NO_Xconcentration.

(i) The sampling site and location shall be the same as for the SO_2sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_Xsample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2concentration ($\%O_2$). The sample shall be taken simultaneously with, and at the same point as, the NO_Xsample.

(iii) The NO_Xemission rate shall be computed for each pair of $NO_X$and O_2samples. The NO_Xemission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

(c) When combinations of fossil fuels or fossil fuel and wood residue are fired, the owner or operator (in order to compute the prorated standard as shown in §§60.43(b) and 60.44(b)) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:

(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

(2) ASTM Methods D2015, or D5865 (solid fuels), D240 (liquid fuels), or D1826 (gaseous fuels) (all of these methods are incorporated by reference, see §60.17) shall be used to determine the gross calorific values of the fuels. The method used to determine the calorific value of wood residue must be approved by the Administrator.

(3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

(d) The owner or operator may use the following as alternatives to the reference methods and procedures in this section or in other sections as specified:

(1) The emission rate (E) of PM, SO_2 and NO_X may be determined by using the Fc factor, provided that the following procedure is used:

(i) The emission rate (E) shall be computed using the following equation:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where:

E = Emission rate of pollutant, ng/J (lb/MMBtu);

C = Concentration of pollutant, ng/dscm (lb/dscf);

$\%CO_2$ = CO_2 concentration, percent dry basis; and

F_c = Factor as determined in appropriate sections of Method 19 of appendix A of this part.

(ii) If and only if the average Fc factor in Method 19 of appendix A of this part is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B of appendix A of this part shall be used to determine the O_2 and CO_2 concentration according to the procedures in paragraph (b)(2)(ii), (4)(ii), or (5)(ii) of this section. Then if F_o (average of three runs), as calculated from the equation in Method 3B of appendix A of this part, is more than ±3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19 of appendix A of this part, *i.e.* , F_{oa} = 0.209 (F_{da}/F_{ca}), then the following procedure shall be followed:

(A) When F_o is less than 0.97 F_{oa}, then E shall be increased by that proportion under 0.97 F_{oa}, *e.g.* , if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When F_o is less than 0.97 F_{oa} and when the average difference (d) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{oa}, *e.g.* , if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When F_o is greater than 1.03 F_{oa} and when the average difference d is positive, then E shall be decreased by that proportion over 1.03 F_{oa}, *e.g.* , if F_o is 1.05 F_{oa}, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B of appendix A–3 of this part, Method 17 of appendix A–6 of this part may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (3 20 °F). The procedures of sections 8.1 and 11.1 of

Method 5B of appendix A–3 of this part may be used with Method 17 of appendix A–6 of this part only if it is used after wet FGD systems. Method 17 of appendix A–6 of this part shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and SO_2 may be determined simultaneously with the Method 5 of appendix A of this part train provided that the following changes are made:

(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 of appendix A of this part is used in place of the condenser (section 2.1.7) of Method 5 of appendix A of this part.

(ii) All applicable procedures in Method 8 of appendix A of this part for the determination of SO_2 (including moisture) are used:

(4) For Method 6 of appendix A of this part, Method 6C of appendix A of this part may be used. Method 6A of appendix A of this part may also be used whenever Methods 6 and 3B of appendix A of this part data are specified to determine the SO_2 emission rate, under the conditions in paragraph (d)(1) of this section.

(5) For Method 7 of appendix A of this part, Method 7A, 7C, 7D, or 7E of appendix A of this part may be used. If Method 7C, 7D, or 7E of appendix A of this part is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O_2 concentration (% O_2) for the emission rate correction factor.

(6) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used.

(7) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used.

[60 FR 65415, Dec. 19, 1995, as amended at 74 FR 5078, Jan. 28, 2009]

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Appendix B

Continuous Emission Monitoring Systems Conditions

Arkansas Department of Environmental Quality

CONTINUOUS EMISSION MONITORING SYSTEMS CONDITIONS

Revised August 2004

PREAMBLE

These conditions are intended to outline the requirements for facilities required to operate Continuous Emission Monitoring Systems/Continuous Opacity Monitoring Systems (CEMS/COMS). Generally there are three types of sources required to operate CEMS/COMS:

1. CEMS/COMS required by 40 CFR Part 60 or 63,
2. CEMS required by 40 CFR Part 75,
3. CEMS/COMS required by ADEQ permit for reasons other that Part 60, 63 or 75.

These CEMS/COMS conditions are not intended to supercede Part 60, 63 or 75 requirements.

- Only CEMS/COMS in the third category (those required by ADEQ permit for reasons other than Part 60, 63, or 75) shall comply with SECTION II, MONITORING REQUIREMENTS and SECTION IV, QUALITY ASSURANCE/QUALITY CONTROL.

- All CEMS/COMS shall comply with Section III, NOTIFICATION AND RECORDKEEPING.

SECTION I

DEFINITIONS

Continuous Emission Monitoring System (CEMS) - The total equipment required for the determination of a gas concentration and/or emission rate so as to include sampling, analysis and recording of emission data.

Continuous Opacity Monitoring System (COMS) - The total equipment required for the determination of opacity as to include sampling, analysis and recording of emission data.

Calibration Drift (CD) - The difference in the CEMS output reading from the established reference value after a stated period of operation during which no unscheduled maintenance, repair, or adjustments took place.

Back-up CEMS (Secondary CEMS) - A CEMS with the ability to sample, analyze and record stack pollutant to determine gas concentration and/or emission rate. This CEMS is to serve as a back-up to the primary CEMS to minimize monitor downtime.

Excess Emissions - Any period in which the emissions exceed the permit limits.

Monitor Downtime - Any period during which the CEMS/COMS is unable to sample, analyze and record a minimum of four evenly spaced data points over an hour, except during one daily zero-span check during which two data points per hour are sufficient.

Out-of-Control Period - Begins with the time corresponding to the completion of the fifth, consecutive, daily CD check with a CD in excess of two times the allowable limit, or the time corresponding to the completion of the daily CD check preceding the daily CD check that results in a CD in excess of four times the allowable limit and the time corresponding to the completion of the sampling for the RATA, RAA, or CGA which exceeds the limits outlined in Section IV. Out-of-Control Period ends with the time corresponding to the completion of the CD check following corrective action with the results being within the allowable CD limit or the completion of the sampling of the subsequent successful RATA, RAA, or CGA.

Primary CEMS - The main reporting CEMS with the ability to sample, analyze, and record stack pollutant to determine gas concentration and/or emission rate.

Relative Accuracy (RA) - The absolute mean difference between the gas concentration or emission rate determined by the CEMS and the value determined by the reference method plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the reference method tests of the applicable emission limit.

Span Value – The upper limit of a gas concentration measurement range.

SECTION II

MONITORING REQUIREMENTS

A. For new sources, the installation date for the CEMS/COMS shall be no later than thirty (30) days from the date of start-up of the source.

B. For existing sources, the installation date for the CEMS/COMS shall be no later than sixty (60) days from the issuance of the permit unless the permit requires a specific date.

C. Within sixty (60) days of installation of a CEMS/COMS, a performance specification test (PST) must be completed. PST's are defined in 40 CFR, Part 60, Appendix B, PS 1-9. The Department may accept alternate PST's for pollutants not covered by Appendix B on a case-by-case basis. Alternate PST's shall be approved, in writing, by the ADEQ CEM Coordinator prior to testing.

D. Each CEMS/COMS shall have, as a minimum, a daily zero-span check. The zero-span shall be adjusted whenever the 24-hour zero or 24-hour span drift exceeds two times the limits in the applicable performance specification in 40 CFR, Part 60, Appendix B. Before any adjustments are made to either the zero or span drifts measured at the 24-hour interval the excess zero and span drifts measured must be quantified and recorded.

E. All CEMS/COMS shall be in continuous operation and shall meet minimum frequency of operation requirements of 95% up-time for each quarter for each pollutant measured. Percent of monitor down-time is calculated by dividing the total minutes the monitor is not in operation by the total time in the calendar quarter and multiplying by one hundred. Failure to maintain operation time shall constitute a violation of the CEMS conditions.

F. Percent of excess emissions are calculated by dividing the total minutes of excess emissions by the total time the source operated and multiplying by one hundred. Failure to maintain compliance may constitute a violation of the CEMS conditions.

G. All CEMS measuring emissions shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive fifteen minute period unless more cycles are required by the permit. For each CEMS, one-hour averages shall be computed from four or more data points equally spaced over each one hour period unless more data points are required by the permit.

H. All COMS shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

I. When the pollutant from a single affected facility is released through more than one point, a CEMS/COMS shall be installed on each point unless installation of fewer systems is approved, in writing, by the ADEQ CEM Coordinator. When more than one CEM/COM is used to monitor emissions from one affected facility the owner or operator shall report the results as required from each CEMS/COMS.

SECTION III

NOTIFICATION AND RECORD KEEPING

A. When requested to do so by an owner or operator, the ADEQ CEM Coordinator will review plans for installation or modification for the purpose of providing technical advice to the owner or operator.

B. Each facility which operates a CEMS/COMS shall notify the ADEQ CEM Coordinator of the date for which the demonstration of the CEMS/COMS performance will commence (i.e. PST, RATA, RAA, CGA). Notification shall be received in writing no less than 15 days prior to testing. Performance test results shall be submitted to the Department within thirty days after completion of testing.

C. Each facility which operates a CEMS/COMS shall maintain records of the occurrence and duration of start up/shut down, cleaning/soot blowing, process problems, fuel problems, or other malfunction in the operation of the affected facility which causes excess emissions. This includes any malfunction of the air pollution control equipment or any period during which a continuous monitoring device/system is inoperative.

D. Except for Part 75 CEMs, each facility required to install a CEMS/COMS shall submit an excess emission and monitoring system performance report to the Department (Attention: Air Division, CEM Coordinator) at least quarterly, unless more frequent submittals are warranted to assess the compliance status of the facility. Quarterly reports shall be postmarked no later than the 30th day of the month following the end of each calendar quarter. Part 75 CEMs shall submit this information semi-annually and as part of Title V six (6) month reporting requirement if the facility is a Title V facility.

E. All excess emissions shall be reported in terms of the applicable standard. Each report shall be submitted on ADEQ Quarterly Excess Emission Report Forms. Alternate forms may be used with prior written approval from the Department.

F. Each facility which operates a CEMS/COMS must maintain on site a file of CEMS/COMS data including all raw data, corrected and adjusted, repair logs, calibration checks, adjustments, and test audits. This file must be retained for a period of at least five years, and is required to be maintained in such a condition that it can easily be audited by an inspector.

G. Except for Part 75 CEMs, quarterly reports shall be used by the Department to determine compliance with the permit. For Part 75 CEMs, the semi-annual report shall be used.

SECTION IV

QUALITY ASSURANCE/QUALITY CONTROL

A. For each CEMS/COMS a Quality Assurance/Quality Control (QA/QC) plan shall be submitted to the Department (Attn.: Air Division, CEM Coordinator). CEMS quality assurance procedures are defined in 40 CFR, Part 60, Appendix F. This plan shall be submitted within 180 days of the CEMS/COMS installation. A QA/QC plan shall consist of procedure and practices which assures acceptable level of monitor data accuracy, precision, representativeness, and availability.

B. The submitted QA/QC plan for each CEMS/COMS shall not be considered as accepted until the facility receives a written notification of acceptance from the Department.

C. Facilities responsible for one, or more, CEMS/COMS used for compliance monitoring shall meet these minimum requirements and are encouraged to develop and implement a more extensive QA/QC program, or to continue such programs where they already exist. Each QA/QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CEMS/COMS
   a. Daily calibrations (including the approximate time(s) that the daily zero and span drifts will be checked and the time required to perform these checks and return to stable operation)
2. Calibration drift determination and adjustment of CEMS/COMS
   a. Out-of-control period determination
   b. Steps of corrective action
3. Preventive maintenance of CEMS/COMS
   a. CEMS/COMS information
      1) Manufacture
      2) Model number
      3) Serial number
   b. Scheduled activities (check list)
   c. Spare part inventory
4. Data recording, calculations, and reporting
5. Accuracy audit procedures including sampling and analysis methods
6. Program of corrective action for malfunctioning CEMS/COMS

D. A Relative Accuracy Test Audit (RATA), shall be conducted at least once every four calendar quarters. A Relative Accuracy Audit (RAA), or a Cylinder Gas Audit (CGA), may be conducted in the other three quarters but in no more than three quarters in succession. The RATA should be conducted in accordance with the applicable test procedure in 40 CFR Part 60 Appendix A and calculated in accordance with the applicable performance specification in 40 CFR Part 60 Appendix B. CGA's and RAA's should be conducted and the data calculated in accordance with the procedures outlined on 40 CFR Part 60 Appendix F.

If alternative testing procedures or methods of calculation are to be used in the RATA, RAA or CGA audits prior authorization must be obtained from the ADEQ CEM Coordinator.

E. Criteria for excessive audit inaccuracy.

RATA

All Pollutants except Carbon Monoxide	> 20% Relative Accuracy
Carbon Monoxide	> 10% Relative Accuracy
All Pollutants except Carbon Monoxide	> 10% of the Applicable Standard
Carbon Monoxide	> 5% of the Applicable Standard
Diluent (O_2 & CO_2)	> 1.0 % O2 or CO2
Flow	> 20% Relative Accuracy

CGA

Pollutant	> 15% of average audit value or 5 ppm difference
Diluent (O_2 & CO_2)	> 15% of average audit value or 5 ppm difference

RAA

Pollutant	> 15% of the three run average or > 7.5 % of the applicable standard
Diluent (O_2 & CO_2)	> 15% of the three run average or > 7.5 % of the applicable standard

F. If either the zero or span drift results exceed two times the applicable drift specification in 40 CFR, Part 60, Appendix B for five consecutive, daily periods, the CEMS is out-of-control. If either the zero or span drift results exceed four times the applicable drift specification in Appendix B during a calibration drift check, the CEMS is out-of-control. If the CEMS exceeds the audit inaccuracies listed above, the CEMS is out-of-control. If a CEMS is out-of-control, the data from that out-of-control period is not counted towards meeting the minimum data availability as required and described in the applicable subpart. The end of the out-of-control period is the time corresponding to the completion of thc successful daily zero or span drift or completion of the successful CGA, RAA or RATA.

G. A back-up monitor may be placed on an emission source to minimize monitor downtime. This back-up CEMS is subject to the same QA/QC procedure and practices as the primary CEMS. The back-up CEMS shall be certified by a PST. Daily zero-span checks must be performed and recorded in accordance with standard practices. When the primary CEMS goes down, the back-up CEMS may then be engaged to sample, analyze and record the emission source pollutant until repairs are made and the primary unit is placed back in service. Records must be maintained on site when the back-up CEMS is placed in service, these records shall include at a minimum the reason the primary CEMS is out of service, the date and time the primary CEMS was out of service and the date and time the primary CEMS was placed back in service.

Appendix C

Maintenance Plan for SN-04 and Design Specifications for SN-17 and SN-18

White Bluff Fly Ash Silo Baghouse Maintenance Plan

Preventative maintenance conducted as scheduled in
AIM, Maintenance Management System.

PM Check sheets are associated with each individual PM, not
Fly ash Silo baghouse system as a whole

1. Check/Adjust Fan, Blowback Exh Baghouse Filter

2. Check/Adjust Blowback Baghouse Filter

3. Check/Adjust Fan, Exh. Baghouse Filter

4 Check/Adjust Filter. Baghouse
   a. Check for air leaks on pulsation system.
   b. Check operation of air operated valves.
   c. Check piping and supports.
   d. Check air cylinders.
   e. Check bag house doors and seals.
   f. Check diffuser blower bearings for heat, vibration, and lubrication leaks.
   g. Check bags and change as needed.
   h. Check blower for excessive heat buildup.
   i. Check inlet filter and change as needed.

5. Check/Adjust WS Dust Baghouse

6. Check/Adjust Traveler Baghouse Filter

7. Check/Adjust Chute, Telescopic, East, West Fly Ash Silo

8 Check/Adjust Fly Ash Diffuser Bower

CT-232

NATURAL DRAFT COOLING TOWER

OPERATING AND MAINTENANCE INSTRUCTIONS

ARKANSAS POWER AND LIGHT

White Bluff STEAM ELECTRIC STATION

UNITS #1 AND #2

RESEARCH-COTTRELL, INC.

HAMON COOLING TOWER DIVISION

P.O. BOX 1500

SOMERVILLE, NEW JERSEY 08876

CT-232

SECTION 1

GENERAL DESCRIPTION

1.1 Description of the Tower

1.1.1 Introduction

Units No. 1 and 2 of the Arkansas Power and Light White Bluff Steam Electric Station are each equipped with a natural draft cooling tower. Each tower is designed according to the counter-flow principle and incorporates asbestos cement fill sheets as the heat transfer surface to assure maximum availability for year-round operation, to minimize maintenance, and to virtually eliminate any necessity for replacement of parts or material.

Each tower consists of five major parts:

1) The basin, to catch and store the cooled water;
2) The fill or heat transfer surface, where the hot water and cooling air come into contact;
3) The distribution system, to distribute the hot water evenly over the fill;
4) The drift eliminator section, to reduce water droplet carry-over;
5) The chimney or veil, to create the draft necessary for tower operation.

Each tower is also equipped with a lightning protection system.

1.1.2 Basin

The cold water basin covers the entire base of the tower and is 314 feet in diameter. It contains approximately 2,900,000 gallons of water when filled to operating level, one foot below the top of the basin wall.

1.1.3 Fill

The fill consists of a variable number of tiers of asbestos cement fill sheets, supported by concrete columns and precast beams.

1.1.4 Distribution System

Warm water enters the tower from the condenser outlet through one concrete pipe that supplies water to three risers in-line. These risers are 114, 102 and 84 inches in diameter and supply water to concrete distribution flumes.

Each flume is fitted with asbestos-cement distribution pipes that distribute the warm water to all sections of the tower fill. Each segment of pipe is fitted with evenly-spaced nozzles made of plastic and fitted with a splashplate. These distribute the water uniformly over the entire fill.

The water leaving the splashplates falls onto the fill sheets, runs down the sheets and then falls to the cold water basin below. The falling wat-

1.1.5 Drift Eliminators

Immediately above the distribution piping network are the drift eliminator waves supported by the concrete structure. The drift eliminators reduce the quantity of water droplets entrained in the air that leave the tower as drift.

1.1.6 Veil

The veil is constructed of reinforced concrete. It is 393 feet high (from the top of the basin wall) and has a minimum wall thickness of 7 inches. The shell is supported by diagonal columns that provide an open air inlet at the base of the tower. The hyperbolic shape of the shell is for economic and structural reasons.

1.1.7 Deicing System

Operational control during normal winter conditions is provided by the deicing system. Deicing is provided by slide gates in two of the risers that can stop the flow of water to the central portion of the tower, thereby increasing the water flow and heat load to the peripheral portions of the tower. In this way, ice formation on the fill is prevented.

1.1.8 Bypass System

A bypass system has been provided to prevent icing of the fill during a freezing weather start-up. When the unit is started up during freezing weather, the warm water flow to the tower fill should be bypassed into the cold water basin. Operation of the bypass is covered in paragraphs 4.3.3 and 4.3.4.

1.2 Principle of Operation

The function of the cooling tower is to cool the water entering the tower at a particular temperature to a lower, specified temperature so that it can be recycled. The tower utilizes cool ambient air in such a way that heat is transferred from the hot water to the cool air through both latent heat transfer and, to a lesser extent, sensible heat transfer.

Hot water evaporates when exposed to cool air. Approximately 1000 BTU of heat per pound of water evaporated is consumed; this heat is taken from the water remaining after evaporation by lowering its temperature. This transfer of latent heat accounts for approximately 75% of the heat transfer that occurs. The rest involves sensible heat exchange. When two masses having different temperatures come into contact, heat is exchanged with the result that their temperatures approach an equilibrium. When warm water contacts cool air in the tower, the air is warmed because it receives sensible heat from the water; the water in turn loses sensible heat and is cooled.

As the air is warmed, it also becomes lighter. The difference in specific weight between the air inside and outside the tower causes the natural draft through the tower. The actual transfer of heat from the water to the air is accomplished primarily in the fill, where warm water is passed downward in very thin films through a stream of air moving upward as a result of the natural draft. The fill is designed to maximize the surface area of the water exposed to air, thereby maximizing the amount of evaporation that occurs. The warmed, moist air is then drawn upward through the drift eliminators by the natural draft. The drift eliminators, composed of panels containing wave-shaped passages, are designed to reduce the amount of water leaving the tower as droplets with the warmed air. By causing the air to change direction, the drift eliminators collect many of the water droplets carried by the air. The warm air is then discharged into the atmosphere and the cooled water falls to the basin to be recycled.

1.3 Material List of Non-Concrete Materials

1.3.1 Fill

Fill Sheets	- Asbestos cement, Type II cement.
Fill Spacers	- Polystyrene. Burning Rate 1.4 in./min. by ASTM D-635.

1.3.2 Drift Eliminators

Drift Eliminator Waves	- Asbestos cement, Type II cement.
Drift Eliminator Spacers	- Polyethylene Flame Spread Rating = 1.4"/min. by ASTM D-635
Drift Eliminator Hardware	- Stainless Steel, Type 304

1.3.3 Distribution System

Distribution Piping	- Asbestos-Cement, ASTM C-428 Type I Autoclave Cured or Equal; Not Combustible.
Pipe Hangers	- Stainless Steel, Type 304
Splashplate	- Acetal
Plastic Nozzle Parts	- Polyethylene and Phenylene Oxide, Flame Spread Rating = 1.04"/min. by ASTM D-635.
Plastic Nozzle Hardware	- Stainless Steel, Type 304
End Plugs	- Polystyrene ASTM D-1892 with Neoprene Gaskets and 304 Stainless Steel Hardware and End Pins.

1.3.4 Miscellaneous

Veil Access Door	- Redwood and Stainless Steel Type 304, heavy-duty construction
Windscreen	- Precast concrete frame with fiberglass panels
Access Hatches	- Fiberglass Panel - Robertson Resolite, Fire Snuf 35.

1.4 Operating Specifications - Design Conditions

Heat Load	- 4.36×10^9 BTU/hr
Waterflow	- 310,000 GPM
Range	- 28.1 degrees F
Wet Bulb	- 78 degrees F
Dry Bulb	- 94 degrees F
Cold Water	- 95 degrees F
Approach	- 17 degrees F
Relative Humidity	- 50 percent
Evaporative Loss*	- 2.46 percent
Drift Loss*	- 0.01 percent

See performance curves in Section 6.1 for additional data.

*Percent of circulating waterflow.

SECTION 2

CIRCULATING WATER QUALITY

2.1 Conditions to be Maintained

For continued maximum cooling tower performance and material life, the circulating water should be subjected to regular analysis to ensure that the following conditions exist. In addition to maintaining the integrity of the concrete components of the tower, these conditions will also ensure that there is no detrimental effect to any plastic materials. Any deviations from these conditions should be kept as short as possible.

2.1.1 The Langelier Index should be maintained at zero or at a slightly positive value, and not less than -0.1.

2.1.2 The pH should not be less than 6.5, as determined at 25 degrees C (77 degrees F).

2.1.3 Concentrations of chemicals harmful to cement should be maintained below reasonable levels, with particular attention being paid to the following:

(SO_4)	Not to exceed 1,000 ppm
(S^-)	Not to exceed 2 ppm
(NH_4^+)	Not to exceed 5 ppm

2.1.4 Aromatic hydrocarbons (organic solvents) and petroleum-based substances should not be allowed to circulate in the cooling system because of possible damage to plastic materials.

2.1.5 Algae formation and growth should be adequately controlled.

2.2 Desilting

Significant amounts of mud or suspended matter will normally be sufficiently taken care of through the normal maintenance procedures (Section 3), but abnormal conditions may require the institution of more frequent desilting.

2.3 Make-Up and Blow-Down

2.3.1 The evaporation process results in a loss of water from the closed-circulating water system. At full load, the evaporation loss is approximately 7600 GPM and the drift loss is approximately 30 GPM. When water is removed by the evaporation process, no dissolved solids are removed and, in time, the circulating water will contain more solids than can remain in solution. In order to prevent this condition, which would scale and foul the components of the system, blow-down is required.

2.3.2 The amount of make-up water to be supplied to the cooling tower should be sufficient to compensate for the evaporation losses, the drift losses, plus the calculated blow-down necessary for optimum concentration within the cooling water circuit.

Appendix D

Dust Control Plan for SN-19

White Bluff Plant
Barge Unloading Operation
Haul Road Dust Control Plan

This Dust Control Plan is only required when the Barge Unloading Facility is in operation. This Dust Control Plan only applies to the paved and unpaved road sections used to transport coal, by truck, from the barge unloading facility to the coal yard.

Paved Roads:
Paved roads will be mechanically swept once weekly. Wetting agent (water or other non-VOC, non-HAP material) will be applied as needed to keep the paved roads wet. Paved roads shall be kept wet at all times when the temperature is greater than 40° F. Wetting will not be required when the temperature is equal to or less than 40°F. Sweeping will be required twice weekly when the temperature is equal to or less than 40°F for more than three (3) consecutive days.

Unpaved Roads:
A non-VOC, non-HAP chemical dust suppressant will be applied to the unpaved road section as needed to control dust.
A MSDS will be maintained on site to demonstrate a non-VOC, non-HAP dust suppressant is used.

Appendix E

Acid Rain Permit Application

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ~ new ~ revised X for Acid Rain permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name: White Bluff Plant	State: AR	Plant Code: 6009

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
1	Yes
2	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Facility (Source) Name: White Bluff Plant

Permit Requirements

STEP 3

Read the standard requirements.

(1) The designated representative of each affected source and each affected unit at the source shall:
(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;
(2) The owners and operators of each affected source and each affected unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

Facility (Source) Name: White Bluff Plant

Recordkeeping and Reporting Requirements, Cont'd.

STEP 3, Cont'd.

(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating

Facility (Source) Name: White Bluff Plant

Effect on Other Authorities, Cont'd.

STEP 3, Cont'd.

to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; *provided,* that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

STEP 4
Read the certification statement, sign, and date.

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name: Myra Glover	
Signature Myra Glover	Date 10-19-09

Instructions for the Acid Rain Program Permit Application

The Acid Rain Program requires the designated representative to submit an Acid Rain permit application for each source with an affected unit. A complete Certificate of Representation must be received by EPA before the permit application is submitted to the title V permitting authority. A complete Acid Rain permit application, once submitted, is binding on the owners and operators of the affected source and is enforceable in the absence of a permit until the title V permitting authority either issues a permit to the source or disapproves the application.

Please type or print. If assistance is needed, contact the title V permitting authority.

STEP 1 A Plant Code is a 4 or 5 digit number assigned by the Department of Energy=s (DOE) Energy Information Administration (EIA) to facilities that generate electricity. For older facilities, "Plant Code" is synonymous with "ORISPL" and "Facility" codes. If the facility generates electricity but no Plant Code has been assigned, or if there is uncertainty regarding what the Plant Code is, contact EIA at (202) 586-4325 or (202) 586-2402.

STEP 2 In column "a," identify each unit at the facility by providing the appropriate unit identification number, consistent with the identifiers used in the Certificate of Representation and with submissions made to DOE and/or EIA. Do not list duct burners. For new units without identification numbers, owners and operators must assign identifiers consistent with EIA and DOE requirements. Each Acid Rain Program submission that includes the unit identification number(s) (e.g., Acid Rain permit applications, monitoring plans, quarterly reports, etc.) should reference those unit identification numbers in exactly the same way that they are referenced on the Certificate of Representation.

Submission Deadlines

For new units, an initial Acid Rain permit application must be submitted to the title V permitting authority 24 months before the date the unit commences operation. Acid Rain permit renewal applications must be submitted at least 6 months in advance of the expiration of the acid rain portion of a title V permit, or such longer time as provided for under the title V permitting authority=s operating permits regulation.

Submission Instructions

Submit this form to the appropriate title V permitting authority. If you have questions regarding this form, contact your local, State, or EPA Regional Acid Rain contact, or call EPA's Acid Rain Hotline at (202) 343-9620.

Paperwork Burden Estimate

The public reporting and record keeping burden for this collection of information is estimated to average 8 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. **Do not send the completed form to this address.**

Appendix F

Clean Air Interstate Rule (CAIR) Permit Application

TITLE V PERMIT
SUPPLEMENTAL PACKAGE
CLEAN AIR INTERSTATE RULE PERMIT APPLICATION

AFIN:	35-00110	Date:	4/22/2008

1. UNIT INFORMATION

Enter the Source ID and Description (as identified in your Arkansas Title V Permit).

Source Number	Description
SN-01	Unit 1 Boiler
SN-02	Unit 2 Boiler

2. STANDARD REQUIREMENTS

Read the standard requirements and the certification. Enter the name of the CAIR designated representative, and sign and date. Include the supplemental application along with a completed Arkansas Operating Permit (Major Source) General Information Forms (pages 1-6). The Department will process a modification to the facility's Title V permit to incorporate these CAIR requirements.

NO_x Ozone Season Emission Requirements
§ 96.306 Standard requirements
(a) *Permit requirements.*
(1) The CAIR designated representative of each CAIR NO_X Ozone Season source required to have a title V operating permit and each CAIR NO_X Ozone Season unit required to have a title V operating permit at the source shall:
(i) Submit to the permitting authority a complete CAIR permit application under §96.322 in accordance with the deadlines specified in §96.321(a) and (b); and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.
(2) The owners and operators of each CAIR NO_X Ozone Season source required to have a title V operating permit and each CAIR NO_X Ozone Season unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCCC of 40 CFR part 96 for the source and operate the source and the unit in compliance with such CAIR permit.
(3) Except as provided in subpart IIII of 40 CFR part 96, the owners and operators of a CAIR NO_X Ozone Season source that is not otherwise required to have a title V operating permit and each CAIR NO_X Ozone Season unit that is not otherwise required to have a title V operating

permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CCCC of 40 CFR part 96 for such CAIR NO_X Ozone Season source and such CAIR NO_X Ozone Season unit.

(b) *Monitoring, reporting, and recordkeeping requirements.*
(1) The owners and operators, and the CAIR designated representative, of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of 40 CFR part 96.
(2) The emissions measurements recorded and reported in accordance with subpart HHHH of 40 CFR part 96 shall be used to determine compliance by each CAIR NO_X Ozone Season source with the CAIR NO_X Ozone Season emissions limitation under paragraph (c) of this §96.306.

(c) *Nitrogen oxides ozone season emission requirements.*
(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, CAIR NO_X Ozone Season allowances available for compliance deductions for the control period under §96.354(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X Ozone Season units at the source, as determined in accordance with subpart HHHH of this part.
(2) A CAIR NO_X Ozone Season unit shall be subject to the requirements under paragraph (c)(1) of this §96.306 starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §96.370(b)(1), (2), (3), or (7) and for each control period thereafter.
(3) A CAIR NO_X Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of §96.306, for a control period in a calendar year before the year for which the CAIR NO_X Ozone Season allowance was allocated.
(4) CAIR NO_X Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Ozone Season Allowance Tracking System accounts in accordance with subparts, FFFF, GGGG of 40 CFR part 96 and Chapter 14 of the Arkansas Pollution Control and Ecology Commission Regulation 19, Regulations of the Arkansas Plan of Implementation for Air Pollution Control.
(5) A CAIR NO_X Ozone Season allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_X Ozone Season Trading Program. No provision of the CAIR NO_X Ozone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.305 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.
(6) A CAIR NO_X Ozone Season allowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart FFFF, GGGG of this part or Chapter 14 of the Arkansas Pollution Control and Ecology Commission Regulation 19, Regulations of the Arkansas Plan of Implementation for Air Pollution Control, every allocation, transfer, or deduction of a CAIR NO_X Ozone Season allowance to or from a CAIR NO_X Ozone Season source's compliance account is incorporated automatically in any CAIR permit of the source.

(d) *Excess emissions requirements.*

(1) If a CAIR NO_X Ozone Season source emits nitrogen oxides during any control period in excess of the CAIR NO_X Ozone Season emissions limitation, then:
(i) The owners and operators of the source and each CAIR NO_X Ozone Season unit at the source shall surrender the CAIR NO_X Ozone Season allowances required for deduction under §96.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and
(ii) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) *Recordkeeping and reporting requirements.*
(1) Unless otherwise provided, the owners and operators of the CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.
(i) The certificate of representation under §96.313 for the CAIR designated representative for the source and each CAIR NO_X Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §96.313 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with subpart HHHH of 40 CFR part 96, provided that to the extent that subpart HHHH of 40 CFR part 96 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X Ozone Season Trading Program.
(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_X Ozone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NO_X Ozone Season Trading Program.
(2) The CAIR designated representative of a CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall submit the reports required under the CAIR NO_X Ozone Season Trading Program, including those under subpart HHHH of 40 CFR part 96.

(f) *Liability.*
(1) Each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit shall meet the requirements of the CAIR NO_X Ozone Season Trading Program.
(2) Any provision of the CAIR NO_X Ozone Season Trading Program that applies to a CAIR NO_X Ozone Season source or the CAIR designated representative of a CAIR NO_X Ozone Season source shall also apply to the owners and operators of such source and of the CAIR NO_X Ozone Season units at the source.
(3) Any provision of the CAIR NO_X Ozone Season Trading Program that applies to a CAIR NO_X Ozone Season unit or the CAIR designated representative of a CAIR NO_X Ozone Season unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.*

No provision of the CAIR NO_X Ozone Season Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §96.305 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X Ozone Season source or CAIR NO_X Ozone Season unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

3. CERTIFICATION

I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

CAIR Designated Representative

Myra Glover **Name (Print)**	Myra H. Glover		
Signature	Myra H. Glover	**Date**	4/28/08

Appendix G

40 CFR Part 63, Subpart ZZZZ - *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

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Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES (CONTINUED)

Browse Next

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Source: 69 FR 33506, June 15, 2004, unless otherwise noted.

What This Subpart Covers

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008]

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f)

and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(vi) Existing residential emergency stationary RICE located at an area source of HAP emissions;

(vii) Existing commercial emergency stationary RICE located at an area source of HAP emissions; or

(viii) Existing institutional emergency stationary RICE located at an area source of HAP emissions.

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60*. An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010]

§ 63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

Emission and Operating Limitations

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§ 63.6602 What emission limitations must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

[75 FR 51589, Aug. 20, 2010]

§ 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 1b and Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the Federal Aid Highway System (FAHS) you do not have to meet the numerical CO emission limitations specified in Table 2d to this subpart. Existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the FAHS must meet the management practices that are shown for stationary non-emergency CI RICE less than or equal to 300 HP in Table 2d to this subpart.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]

§ 63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?

If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel. Existing non-emergency CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, or at area sources in areas of Alaska not accessible by the FAHS are exempt from the requirements of this section.

[75 FR 51589, Aug. 20, 2010]

General Compliance Requirements

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010]

Testing and Initial Compliance Requirements

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 1)}$$

Where:

C_i= concentration of CO or formaldehyde at the control device inlet,

C_o= concentration of CO or formaldehyde at the control device outlet, and

R = percent reduction of CO or formaldehyde emissions.

(2) You must normalize the carbon monoxide (CO) or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, section 5.2, and the following equation:

$$F_o = \frac{0.209\, F_d}{F_c} \qquad \text{(Eq 2)}$$

Where:

F_o= Fuel factor based on the ratio of oxygen volume to the ultimate CO_2volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d= Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

F_c= Ratio of the volume of CO_2produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

(ii) Calculate the CO_2correction factor for correcting measurement data to 15 percent oxygen, as follows:

$$X_{co_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 3)}$$

Where:

X_{co2}= CO_2correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2correction value, percent.

(iii) Calculate the $NO_X$and SO_2gas concentrations adjusted to 15 percent O_2using CO_2as follows:

$$C_{adj} = C_d \frac{X_{co_2}}{\%CO_2} \qquad \text{(Eq. 4)}$$

Where:

$\%CO_2$= Measured CO_2concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.*, wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010]

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either oxygen or CO_2 at both the inlet and the outlet of the control device according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (5) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.*, thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start landfill or digester gas stationary RICE located at an area source of HAP emissions;

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (g)(2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska not accessible by the FAHS do not have to meet the requirements of paragraph (g) of this section.

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates, and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]

§ 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

Continuous Compliance Requirements

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) [Reserved]

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) *Requirements for emergency stationary RICE.* (1) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed on or after June 12, 2006, or an existing emergency stationary RICE located at an area source of HAP emissions, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1)(i) through (iii) of this section. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1)(i) through (iii) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency RICE beyond 100 hours per year.

(iii) You may operate your emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations. The supply of emergency power to another entity or entities pursuant to financial arrangement is not limited by this paragraph (f)(1)(iii), as long as the power provided by the financial arrangement is limited to emergency power.

(2) If you own or operate an emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed prior to June 12, 2006, you must operate the engine according to the conditions described in paragraphs (f)(2)(i) through (iii) of this section. If you do not operate the engine according to the requirements in paragraphs (f)(2)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance.

(iii) You may operate your emergency stationary RICE for an additional 50 hours per year in non-emergency situations. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010]

Notifications, Reports, and Records

§ 63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9 (b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010]

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10 (a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010]

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i*.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) or (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010]

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

Other Requirements and Information

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in §63.6610(b).

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101–549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, *etc.* Stationary RICE used for peak shaving are not considered emergency stationary RICE. Stationary RICE used to supply power to an electric grid or that supply non-emergency power as part of a financial arrangement with another entity are not considered to be emergency engines, except as permitted under §63.6640(f). All emergency stationary RICE must comply with the requirements specified in §63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes "rich" glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The "lean" glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be

aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X(such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011]

Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary	a. Reduce formaldehyde emissions by 76 percent or more.	Minimize the engine's time spent at idle and minimize the

RICE	If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Table 1bto Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed Spark Ignition 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions and Existing Spark Ignition 4SRB Stationary RICE >500 HP Located at an Area Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions and existing 4SRB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	You must meet the following operating limitation . . .
1. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and using NSCR.	a. Maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. Maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 ℉ and less than or equal to 1250 ℉.
2. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and	Comply with any operating limitations approved by the Administrator.

not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and not using NSCR.	

[76 FR 12867, Mar. 9, 2011]

Table 2ato Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2 until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of	

	formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Table 2bto Subpart ZZZZ of Part 63— Operating Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing Compression Ignition Stationary RICE >500 HP, and Existing 4SLB Stationary RICE >500 HP Located at an Area Source of HAP Emissions

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and compression ignition stationary RICE located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; existing compression ignition stationary RICE >500 HP; and existing 4SLB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	You must meet the following operating limitation . . .
1. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and not using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the	Comply with any operating limitations approved by the Administrator.

requirement to limit the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(g) for a different temperature range.

[75 FR 51593, Aug. 20, 2010, as amended at 76 FR 12867, Mar. 9, 2011]

Table 2cto Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[2]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency,	Limit concentration of	

non-black start CI stationary RICE 100≤HP≤300 HP	CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2	
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever	

	comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2	
12. Non-emergency, non-black start landfill or digester gas-fired stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2	

[1]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[2]Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 51593, Aug. 20, 2010]

Table 2dto Subpart ZZZZ of Part 63— Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black	a. Limit	

start CI stationary RICE >500 HP	concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or		
	b. Reduce CO emissions by 70 percent or more.		
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]		
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and		
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.		
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.		
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation		

	or annually, whichever comes first;[1]		
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first; and		
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.		
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]		
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and		
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.		
8. Non-emergency, non-black start 4SLB stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd at 15 percent O_2; or		
	b. Reduce CO emissions by 93 percent or more.		
9. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation		

	or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
10. Non-emergency, non-black start 4SRB stationary RICE >500 HP	a. Limit concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd at 15 percent O_2; or	
	b. Reduce formaldehyde emissions by 76 percent or more.	
11. Non-emergency, non-black start landfill or digester gas-fired stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1]Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[75 FR 51595, Aug. 20, 2010]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE with a brake horsepower >500 located at major sources; new or reconstructed 4SLB stationary RICE with a brake horsepower ≥250 located at major sources; and new or reconstructed CI stationary RICE with a brake horsepower >500 located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE with a brake horsepower ≥5,000 located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE with a brake horsepower >500 located at major sources and new or reconstructed 4SLB stationary RICE with a brake horsepower 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are not limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year that are not limited use stationary RICE	Limit or reduce CO or formaldehyde emissions	Conduct subsequent performance tests every 8,760 hrs. or 3 years, whichever comes first.

5. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year and are limited use stationary RICE	Limit or reduce CO or formaldehyde emissions	Conduct subsequent performance tests every 8,760 hrs. or 5 years, whichever comes first.

[1]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[75 FR 51596, Aug. 20, 2010]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§63.6610, 63.6611, 63.6612, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. Reduce CO emissions	i. Measure the O_2 at the inlet and outlet of the control device; and	(1) Portable CO and O_2 analyzer	(a) Using ASTM D6522–00 (2005)[a] (incorporated by reference, see §63.14). Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the control device	(1) Portable CO and O_2 analyzer	(a) Using ASTM D6522–00 (2005)[ab] (incorporated by reference, see §63.14) or Method 10 of 40 CFR appendix A. The CO

				concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE	a. Reduce formaldehyde emissions	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i)	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00m (2005)	(a) Measurements to determine O_2concentration must be made at the same time as the measurements for formaldehyde concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[c]provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde	i. Select the sampling port location and the number of	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located

	or CO in the stationary RICE exhaust	traverse points; and	§63.7(d)(1)(i)	at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (2005)	(a) Measurements to determine O_2concentration must be made at the same time and location as the measurements for formaldehyde concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[c]provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. Measure CO at the exhaust of the stationary RICE	(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00 (2005),[a]Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–	(a) CO Concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour longer runs.

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[a]You may also use Methods 3A and 10 as options to ASTM–D6522–00 (2005). You may obtain a copy of ASTM–D6522–00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106. ASTM–D6522–00 (2005) may be used to test both CI and SI stationary RICE.

[b]You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.

[c]You may obtain a copy of ASTM–D6348–03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[75 FR 51597, Aug. 20, 2010]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations and Operating Limitations

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if. . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet

calendar year		temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either

major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year		O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.

7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of formaldehyde and not using NSCR	i. The average formaldehyde concentration determined from the initial performance test is less than or equal to the formaldehyde emission limitation; and

		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
11. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating

		parameters (if any) during the initial performance test.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO or formaldehyde emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
13. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.

[76 FR 12867, Mar. 9, 2011]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, Operating Limitations, Work Practices, and Management Practices

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved;[a] and ii. Collecting the catalyst inlet temperature data according to §63.6625 (b); and iii. Reducing these data to 4-hour rolling

		averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved;[a] and ii. Collecting the approved operating parameter (if any) data according to §63.6625 (b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP,	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to §63.6625 (a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620; and

existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year		ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to §63.6625 (b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to §63.6625 (b); and ii. Reducing these data

		to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a]and ii. Collecting the catalyst inlet temperature data according to §63.6625 (b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the

		performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a] and ii. Collecting the approved operating parameter (if any) data according to §63.6625 (b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency landfill or digester gas stationary SI RICE located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

calendar year		
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625 (b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or

	using oxidation catalyst or NSCR	formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625 (b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using an oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625 (b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the

		catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using an oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625 (b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

[a]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[76 FR 12870, Mar. 9, 2011]

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

For each ...	You must submit a ...	The report must contain ...	You must submit the report ...
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP and operated more than 24 hours per calendar year; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4)	

		i. Semiannually according to the requirements in §63.6650(b)(1)–(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)–(9) for engines that are limited use stationary RICE subject to numerical emission limitations. i. Semiannually according to the requirements in §63.6650(b). i. Semiannually according to the requirements in §63.6650(b).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and i. Annually, according to the requirements in §63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and i. See item 2.a.i.
		c. Any problems or errors suspected with the meters.

		i. See item 2.a.i.	

[75 FR 51603, Aug. 20, 2010]

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in §63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.1	General applicability of the General Provisions	Yes.	
§63.2	Definitions	Yes	Additional terms defined in §63.6675.
§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities and circumvention	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)–(4)	Compliance dates for new and reconstructed sources	Yes.	
§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§63.6(c)(1)–(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)–(4)	[Reserved]		
§63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§63.6(d)	[Reserved]		
§63.6(e)	Operation and maintenance	No.	
§63.6(f)(1)	Applicability of standards	No.	
§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)–(3)	Use of alternate standard	Yes.	
§63.6(h)	Opacity and visible	No	Subpart ZZZZ does

	emission standards		not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes.	
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)–(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.
§63.7(a)(3)	CAA section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes	Except that §63.7(b)(1) only applies as specified in §63.6645.
§63.7(b)(2)	Notification of rescheduling	Yes	Except that §63.7(b)(2) only applies as specified in §63.6645.
§63.7(c)	Quality assurance/test plan	Yes	Except that §63.7(c) only applies as specified in §63.6645.
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at §63.6620.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.
§63.8(a)(2)	Performance specifications	Yes.	
§63.8(a)(3)	[Reserved]		

§63.8(a)(4)	Monitoring for control devices	No.	
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)–(3)	Multiple effluents and multiple monitoring systems	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	Yes.	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	Yes.	
§63.8(c)(2)–(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)–(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
		Except that §63.8(e) only applies as specified in §63.6645.	
§63.8(f)(1)–(5)	Alternative monitoring method	Yes	Except that §63.8(f)(4) only applies as specified in §63.6645.
§63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that §63.8(f)(6) only applies as specified in §63.6645.
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are

			specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§63.9(b)(1)–(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
		Except that §63.9(b) only applies as specified in §63.6645.	
§63.9(c)	Request for compliance extension	Yes	Except that §63.9(c) only applies as specified in §63.6645.
§63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that §63.9(d) only applies as specified in §63.6645.
§63.9(e)	Notification of performance test	Yes	Except that §63.9(e) only applies as specified in §63.6645.
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	Except that §63.9(g) only applies as specified in §63.6645.
§63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that §63.9(g) only applies as specified in §63.6645.	
§63.9(h)(1)–(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
			Except that §63.9(h) only applies as

			specified in §63.6645.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§63.10(b)(1)	Record retention	Yes.	
§63.10(b)(2)(i)–(v)	Records related to SSM	No.	
§63.10(b)(2)(vi)–(xi)	Records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	
§63.10(c)	Additional records for sources using CEMS	Yes	Except that §63.10(c)(2)–(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that §63.10(e)(3)(i) (C) is reserved.
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§63.11	Flares	No.	

§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010]

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Appendix H

40 CFR Part 60, Subpart IIII - *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

Electronic Code of Federal Regulations
e-CFR TM

e-CFR Data is current as of May 10, 2012

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

What This Subpart Covers

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of §60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

Emission Standards for Manufacturers

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater

than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 1 to 40 CFR 1042.1 identifies 40 CFR part 1042 as being applicable, 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the Federal Aid Highway System (FAHS); and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI internal combustion engines identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 2 to 40 CFR 1042.101 identifies Tier 3 standards as being applicable, the requirements applicable to Tier 3 engines in 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the FAHS; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

§ 60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

Emission Standards for Owners and Operators

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in §60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0\ 23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in §60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine

[76 FR 37969, June 28, 2011]

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must purchase diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder are no longer subject to the requirements of paragraph (a) of this section, and must use fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Other Requirements for Owners and Operators

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Compliance Requirements

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and (e) and §60.4202(e) and (f) using the certification procedures required in 40 CFR part 94, subpart C, or 40 CFR part 1042, subpart C, as applicable, and must test their engines as specified in 40 CFR part 94 or 1042, as applicable.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89, 40 CFR part 94 or 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR parts 89, 94, 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103 (b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204 (c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must

include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(e) or §60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in §60.4204(e) or §60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in §60.4212 or §60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. Emergency stationary ICE may operate up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply non-emergency power as part of a financial arrangement with another entity. For owners and operators of emergency engines, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as permitted in this section, is prohibited.

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted

maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011]

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i= concentration of NO_X or PM at the control device inlet,

C_o= concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_X or PM emissions.

(2) You must normalize the NO_X or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \%\, O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$ = Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209 F_d}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_X or PM, uncorrected.

$\%CO_2$= Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \quad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d= Measured NO_X concentration in ppm.

$1.912x10^{-3}$= Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \quad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj}= Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

Notification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Special Requirements

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in §60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than

2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in areas of Alaska not accessible by the FAHS may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in sections §§60.4201(f) and 60.4202(g) of this subpart.

(c) Manufacturers, owners and operators of stationary CI ICE that are located in areas of Alaska not accessible by the FAHS may choose to meet the applicable emission standards for emergency engines in §60.4202 and §60.4205, and not those for non-emergency engines in §60.4201 and §60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine that was not certified as meeting Tier 4 PM standards, must meet the applicable requirements for PM in §60.4201 and §60.4204 or install a PM emission control device that achieves PM emission reductions of 85 percent, or 60 percent for engines with a displacement of greater than or equal to 30 liters per cylinder, compared to engine-out emissions.

(d) The provisions of §60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS

(e) The provisions of §60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and §60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011]

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4204 or §60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

General Provisions

§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Definitions

§ 60.4219 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101 (g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary CI ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.

Engine manufacturer means the manufacturer of the engine. See the definition of "manufacturer" in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see "date of manufacture"), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see "date of manufacture"), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see "date of manufacture").

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007–2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_X+ NMHC	CO	PM
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)

19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)[1]
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

[1]Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)

19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

[1]For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2]For model years 2010–2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3]In model years 2009–2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed[1]	Torque (percent)[2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1]Engine speed: ±2 percent of point.

[2]Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

[As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:]

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, measure	(3) Method 4 of 40 CFR	(c) Measurements to determine

		moisture content at the inlet and outlet of the control device; and,	part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	moisture content must be made at the same time as the measurements for NO_X concentration.
		iv. Measure NO_X at the inlet and outlet of the control device	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and,	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A,	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.

		at the sampling port location; and,	or ASTM D 6348–03 (incorporated by reference, see §60.17)	
		iv. Measure NO_X at the exhaust of the stationary internal combustion engine	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration	i. Select the sampling port	(1) Method 1 or 1A of 40	(a) If using a control device, the

	of PM in the stationary CI internal combustion engine exhaust	location and the number of traverse points;	CFR part 60, appendix A	sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.

§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

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Appendix I

40 CFR Part 63, Subpart UUUUU – *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units*

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR Data is current as of November 6, 2013

Title 40: Protection of Environment
PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES (CONTINUED)

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Contents

TABLES TO SUBPART UUUUU OF PART 63

SOURCE: 77 FR 9464, Feb. 16, 2012, unless otherwise noted.

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WHAT THIS SUBPART COVERS

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§63.9980 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs) as defined in §63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

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§63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU as defined in §63.10042 of this subpart.

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§63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of two or more new, reconstructed, or existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

(1) The affected source of this subpart is the collection of all existing coal- or oil-fired EGUs, as defined in §63.10042, within a subcategory.

(2) The affected source of this subpart is each new or reconstructed coal- or oil-fired EGU as defined in §63.10042.

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in §63.2, and if you commence reconstruction after May 3, 2011.

(d) An EGU is existing if it is not new or reconstructed. An existing electric steam generating unit that meets the applicability requirements after the effective date of this final rule due to a change in process (e.g., fuel or utilization) is considered to be an existing source under this subpart.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012; 78 FR 24084, Apr. 24, 2013]

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§63.9983 Are any EGUs not subject to this subpart?

The types of electric steam generating units listed in paragraphs (a) through (d) of this section are not subject to this subpart.

(a) Any unit designated as a stationary combustion turbine, other than an integrated gasification combined cycle (IGCC) unit, covered by 40 CFR part 63, subpart YYYY.

(b) Any electric utility steam generating unit that is not a coal- or oil-fired EGU and combusts natural gas for more than 10.0 percent of the average annual heat input during any 3 calendar years or for more than 15.0 percent of the annual heat input during any calendar year.

(c) Any electric utility steam generating unit that has the capability of combusting more than 25 MW of coal or oil but did not fire coal or oil for more than 10.0 percent of the average annual heat input during any 3 calendar years or for more than 15.0 percent of the annual heat input during any calendar year. Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and industrial boilers).

(d) Any electric steam generating unit combusting solid waste is a solid waste incineration unit subject to standards established under sections 129 and 111 of the Clean Air Act.

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§63.9984 When do I have to comply with this subpart?

(a) If you have a new or reconstructed EGU, you must comply with this subpart by April 16, 2012 or upon startup of your EGU, whichever is later, and as further provided for in §63.10005(g).

(b) If you have an existing EGU, you must comply with this subpart no later than April 16, 2015.

(c) You must meet the notification requirements in §63.10030 according to the schedule in §63.10030 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(d) An electric steam generating unit that does not meet the definition of an EGU subject to this subpart on April 16, 2012 for new sources or April 16, 2015 for existing sources must comply with the applicable existing source provisions of this subpart on the date such unit meets the definition of an EGU subject to this subpart.

(e) If you own or operate an electric steam generating unit that is exempted from this subpart under §63.9983(d), if the manner of operating the unit changes such that the combustion of waste is discontinued and the unit becomes a coal-fired or oil-fired EGU (as defined in §63.10042), you must be in compliance with this subpart on April 16, 2015 or on the effective date of the switch from waste combustion to coal or oil combustion, whichever is later.

(f) You must demonstrate that compliance has been achieved, by conducting the required performance tests and other activities, no later than 180 days after the applicable date in paragraph (a), (b), (c), (d), or (e) of this section.

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§63.9985 What is a new EGU?

(a) A new EGU is an EGU that meets any of the criteria specified in paragraph (a)(1) through (a)(2) of this section.

(1) An EGU that commenced construction after May 3, 2011.

(2) An EGU that commenced reconstruction after May 3, 2011.

(b) [Reserved]

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012]

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Emission Limitations and Work Practice Standards

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§63.9990 What are the subcategories of EGUs?

(a) Coal-fired EGUs are subcategorized as defined in paragraphs (a)(1) through (a)(2) of this section and as defined in §63.10042.

(1) EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb, and

(2) EGUs designed for low rank virgin coal.

(b) Oil-fired EGUs are subcategorized as noted in paragraphs (b)(1) through (b)(4) of this section and as defined in §63.10042.

(1) Continental liquid oil-fired EGUs

(2) Non-continental liquid oil-fired EGUs,

(3) Limited-use liquid oil-fired EGUs, and

(4) EGUs designed to burn solid oil-derived fuel.

(c) IGCC units combusting either gasified coal or gasified solid oil-derived fuel. For purposes of compliance, monitoring, recordkeeping, and reporting requirements in this subpart, IGCC units are subject in the same manner as coal-fired units and solid oil-derived fuel-fired units, unless otherwise indicated.

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§63.9991 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Table 1 through 3 to this subpart that applies to your EGU, for each EGU at your source, except as provided under §63.10009.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your EGU.

(b) As provided in §63.6(g), the Administrator may approve use of an alternative to the work practice standards in this section.

(c) You may use the alternate SO_2 limit in Tables 1 and 2 to this subpart only if your EGU:

(1) Has a system using wet or dry flue gas desulfurization technology and SO_2 continuous emissions monitoring system (CEMS) installed on the unit; and

(2) At all times, you operate the wet or dry flue gas desulfurization technology installed on the unit consistent with §63.10000(b).

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012]

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General Compliance Requirements

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§63.10000 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, you are required to meet the work practice requirements in Table 3 to this subpart during periods of startup or shutdown.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(c)(1) For coal-fired units, IGCC units, and solid oil-derived fuel-fired units, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct the initial performance testing in accordance with §63.10005(h), to determine whether the unit qualifies as a low emitting EGU (LEE) for one or more applicable emissions limits, with two exceptions:

(A) You may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with an acid gas scrubber and has a main stack and bypass stack exhaust configuration, and

(B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-derived fuel-fired EGU or IGCC EGU is new.

(ii) For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status.

(iii) For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(iv) If your coal-fired or solid oil derived fuel-fired EGU or IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

(v) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), you may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B to this subpart. As an alternative to HCl CEMS, you may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If your EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), you may apply a second alternative to HCl CEMS by installing and operating a sulfur dioxide (SO_2) CEMS installed and operated in accordance with part 75 of this chapter to demonstrate compliance with the applicable SO_2 emissions limit.

(vi) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for Hg, you must demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with appendix A to this subpart.

(2) For liquid oil-fired EGUs, except limited use liquid oil-fired EGUs, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For an existing liquid oil-fired unit, you may conduct the performance testing in accordance with §63.10005(h), to determine whether the unit qualifies as a LEE for one or more pollutants. For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(ii) If your liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, performance testing conducted quarterly.

(iii) If your existing liquid oil-fired unit does not qualify as a LEE for hydrogen chloride (HCl) or for hydrogen fluoride (HF), you may demonstrate initial and continuous compliance through use of an HCl CEMS, an HF CEMS, or an HCl and HF CEMS, installed and operated in accordance with Appendix B to this rule. As an alternative to HCl CEMS, HF CEMS, or HCl and HF CEMS, you may demonstrate initial and continuous compliance by conducting periodic quarterly performance stack tests for HCl and HF. If you elect to demonstrate compliance through quarterly performance testing, then you must also develop a site-specific monitoring plan to ensure that the operations of the unit remain consistent with those during the performance test. As another alternative, you may measure or obtain, and keep records of, fuel moisture content; as long as fuel moisture does not exceed 1.0 percent by weight, you need not conduct other HCl or HF monitoring or testing.

(iv) If your unit qualifies as a limited-use liquid oil-fired as defined in §63.10042, then you are not subject to the emission limits in Tables 1 and 2, but you must comply with the performance tune-up work practice requirements in Table 3.

(d)(1) If you demonstrate compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), you must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation (where applicable) of your CMS. This requirement also applies to you if you petition the Administrator for alternative monitoring parameters under §63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under appendix B to part 60 or part 75 of this chapter, and that meet the requirements of §63.10010. Using the process described in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in your site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs (d)(2) through (5) of this section.

(2) The site-specific monitoring plan shall include the information specified in paragraphs (d)(5)(i) through (d)(5)(vii) of this section. Alternatively, the requirements of paragraphs (d)(5)(i) through (d)(5)(vii) are considered to be met for a particular CMS or sorbent trap monitoring system if:

(i) The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to part 75 of this chapter, or appendix A or B to this subpart; and

(ii) The recordkeeping and reporting requirements of part 75 of this chapter, or appendix A or B to this subpart, that pertain to the CMS are met.

(3) If requested by the Administrator, you must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of §63.10010 (e.g., if the CMS was previously certified under another program).

(4) You must operate and maintain the CMS according to the site-specific monitoring plan.

(5) The provisions of the site-specific monitoring plan must address the following items:

(i) Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See §63.10010(a) for further details. For PM CPMS installations, follow the procedures in §63.10010(h).

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(iii) Schedule for conducting initial and periodic performance evaluations.

(iv) Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of §63.8(d).

(v) On-going operation and maintenance procedures, in accordance with the general requirements of §§63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

(vi) Conditions that define a CMS that is out of control consistent with §63.8(c)(7)(i) and for responding to out of control periods consistent with §§63.8(c)(7)(ii) and (c)(8).

(vii) On-going recordkeeping and reporting procedures, in accordance with the general requirements of §§63.10(c), (e)(1), and (e)(2)(i), or as specifically required under this subpart.

(e) As part of your demonstration of continuous compliance, you must perform periodic tune-ups of your EGU(s), according to §63.10021(e).

(f) You are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (e.g., 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distribution system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless you are a solid waste incineration unit subject to standards under CAA section 129 (e.g., 40 CFR Part 60, Subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or Subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section 129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

(g) If you no longer meet the definition of an EGU subject to this subpart you must be in compliance with any newly applicable standards on the date you are no longer subject to this subpart. The date you are no longer subject to this subpart is a date selected by you, that must be at least 6 months from the date that you last met the definition of an EGU subject to this subpart or the date you begin combusting solid waste, consistent with §63.9983(d). Your source must remain in compliance with this subpart until the date you select to cease complying with this subpart or the date you begin combusting solid waste, whichever is earlier.

(h)(1) If you own or operate an EGU that does not meet the definition of an EGU subject to this subpart on April 16, 2015, and you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart, you are subject to the provisions of this subpart, including, but not limited to, the emission limitations and the monitoring requirements, as of the first day you meet the definition of an EGU subject to this subpart. You must complete all initial compliance demonstrations for this subpart applicable to your EGU within 180 days after you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart.

(2) You must provide 30 days prior notice of the date you intend to commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU, the location of the facility, the unit(s) that will commence or recommence operations that will cause the unit(s) to meet the definition of an EGU subject to this subpart, and the date of the notice;

(ii) The 40 CFR part 60, part 62, or part 63 subpart and subcategory currently applicable to your unit(s), and the subcategory of this subpart that will be applicable after you commence or recommence operation that will cause the unit(s) to meet the definition of an EGU subject to this subpart;

(iii) The date on which you became subject to the currently applicable emission limits;

(iv) The date upon which you will commence or recommence operations that will cause your unit to meet the definition of an EGU subject to this subpart, consistent with paragraph (f) of this section.

(i)(1) If you own or operate an EGU subject to this subpart, and it has been at least 6 months since you operated in a manner that caused you to meet the definition of an EGU subject to this subpart, you may, consistent with paragraph (g) of this section, select the date on which your EGU will no longer be subject to this subpart. You must be in compliance with any newly applicable section 112 or 129 standards on the date you selected.

(2) You must provide 30 days prior notice of the date your EGU will cease complying with this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU(s), the location of the facility, the EGU(s) that will cease complying with this subpart, and the date of the notice;

(ii) The currently applicable subcategory under this subpart, and any 40 CFR part 60, part 62, or part 63 subpart and subcategory that will be applicable after you cease complying with this subpart;

(iii) The date on which you became subject to this subpart;

(iv) The date upon which you will cease complying with this subpart, consistent with paragraph (g) of this section.

(j) All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart.

(k) All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart. All calibration and drift checks must be performed as of the date your source ceases to be or becomes subject to this subpart. You must also comply with provisions of §§63.10010, 63.10020, and 63.10021 of this subpart. Relative accuracy tests must be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under this subpart.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23402, Apr. 19, 2012; 78 FR 24084, Apr. 24, 2013]

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§63.10001 Affirmative defense for exceedence of emission limit during malfunction.

In response to an action to enforce the standards set forth in §63.9991 you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The excess emissions:

(i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(4) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(b) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction or, if it is not possible to determine within two business days whether the malfunction caused or contributed to an exceedance, no later than two business days after the owner or operator knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in §63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

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TESTING AND INITIAL COMPLIANCE REQUIREMENTS

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§63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) *General requirements.* For each of your affected EGUs, you must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing. Where two emissions limits are specified for a particular pollutant (e.g., a heat input-based limit in lb/MMBtu and an electrical output-based limit in lb/MWh), you may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of hourly electrical load data (megawatts); establishment of operating limits according to §63.10011 and Tables 4 and 7 to this subpart; and CMS performance evaluations. In all cases, you must demonstrate initial compliance no later than the applicable date in paragraph (f) of this section for tune-up work practices for existing EGUs, in §63.9984 for other requirements for existing EGUs, and in paragraph (g) of this section for all requirements for new EGUs.

(1) To demonstrate initial compliance with an applicable emissions limit in Table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. If you are required to establish operating limits (see paragraph (d) of this section and Table 4 to this subpart), you must collect all applicable parametric data during the performance test period. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period.

(2) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (*i.e.*, an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO_2 or PM CEMS, the initial performance test consists of 30 boiler operating days of data collected by the initial compliance demonstration date specified in §63.10005 with the certified monitoring system.

(i) The 30-boiler operating day CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO_2 emissions limit in Table 1 or 2 to this subpart.

(ii) If you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the performance test period.

(b) *Performance testing requirements.* If you choose to use performance testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to §63.10007 and Table 5 to this subpart. For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in §63.9984, provided that the following conditions are fully met:

(1) For a performance test based on stack test data, the test was conducted no more than 12 calendar months prior to the date on which compliance is required as specified in §63.9984;

(2) For a performance test based on data from a certified CEMS or sorbent trap monitoring system, the test consists of all valid CMS data recorded in the 30 boiler operating days immediately preceding that date;

(3) The performance test was conducted in accordance with all applicable requirements in §63.10007 and Table 5 to this subpart;

(4) A record of all parameters needed to convert pollutant concentrations to units of the emission standard (e.g., stack flow rate, diluent gas concentrations, hourly electrical loads) is available for the entire performance test period; and

(5) For each performance test based on stack test data, you certify, and keep documentation demonstrating, that the EGU configuration, control devices, and fuel(s) have remained consistent with conditions since the prior performance test was conducted.

(c) *Operating limits.* In accordance with §63.10010 and Table 4 to this subpart, you may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of your initial compliance demonstration.

(d) *CMS requirements.* If, for a particular emission or operating limit, you are required to (or elect to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of §§63.10010(b) through (h), an additional performance evaluation of the CMS is not required under this subpart.

(1) For an affected coal-fired, solid oil-derived fuel-fired, or liquid oil-fired EGU, you may demonstrate initial compliance with the applicable SO_2, HCl, or HF emissions limit in Table 1 or 2 to this subpart through use of an SO_2, HCl, or HF CEMS installed and operated in accordance with part 75 of this chapter or Appendix B to this subpart, as applicable. You may also demonstrate compliance with a filterable PM emission limit in Table 1 or 2 to this subpart through use of a PM CEMS installed, certified, and operated in accordance with §63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS data, expressed in units of the standard (see §63.10007(e)), meets the applicable SO_2, PM, HCl, or HF emissions limit in Table 1 or 2 to this subpart. Use Equation 19-19 of Method 19 in appendix A-7 to part 60 of this chapter to calculate the 30-boiler operating day average emissions rate. (NOTE: For this calculation, the term E_{hj} in Equation 19-19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to this subpart).

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in §63.9984 (f) for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the PM CPMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the emission limit with which you choose to comply.

(iii) You must repeat the performance test annually for the selected pollutant emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in §63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.

(4) For affected liquid oil-fired EGUs that demonstrate compliance with the applicable emission limits for HCl or HF listed in Table 1 or 2 to this subpart using quarterly testing and continuous monitoring with a CMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in §63.9984 for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the CMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the HCl or HF emissions limit.

(iii) You must repeat the performance test annually for the HCl or HF emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(e) *Tune-ups.* All affected EGUs are subject to the work practice standards in Table 3 of this subpart. As part of your initial compliance demonstration, you must conduct a performance tune-up of your EGU according to §63.10021(e).

(f) For existing affected sources a tune-up may occur prior to April 16, 2012, so that existing sources without neural networks have up to 42 calendar months (3 years from promulgation plus 180 days) or, in the case of units employing neural network combustion controls, up to 54 calendar months (48 months from promulgation plus 180 days) after the date that is specified for your source in §63.9984 and according to the applicable provisions in §63.7(a)(2) as cited in Table 9 to this subpart to demonstrate compliance with this requirement. If a tune-up occurs prior to such date, the source must maintain adequate records to show that the tune-up met the requirements of this standard.

(g) If your new or reconstructed affected source commenced construction or reconstruction between May 3, 2011, and July 2, 2011, you must demonstrate initial compliance with either the proposed emission limits or the promulgated emission limits no later than 180 days after April 16, 2012 or within 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(1) For the new or reconstructed affected source described in this paragraph (g), if you choose to comply with the proposed emission limits when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits within 3 years after April 16, 2012 or within 3 years after startup of the affected source, whichever is later.

(2) If your new or reconstructed affected source commences construction or reconstruction after April 16, 2012, you must demonstrate initial compliance with the promulgated emission limits no later than 180 days after startup of the source.

(h) *Low emitting EGUs.* The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. You may not pursue this compliance option if your existing EGU is equipped with an acid gas scrubber and has a main stack and bypass stack exhaust configuration.

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h), and if those data demonstrate:

(i) For all pollutants except Hg, performance test emissions results less than 50 percent of the applicable emissions limits in Table 1 or 2 to this subpart for all required testing for 3 consecutive years; or

(ii) For Hg emissions from an existing EGU, either:

(A) Average emissions less than 10 percent of the applicable Hg emissions limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh); or

(B) Potential Hg mass emissions of 29.0 or fewer pounds per year and compliance with the applicable Hg emission limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh).

(2) For all pollutants except Hg, you must conduct all required performance tests described in §63.10007 to demonstrate that a unit qualifies for LEE status.

(i) When conducting emissions testing to demonstrate LEE status, you must increase the minimum sample volume specified in Table 1 or 2 nominally by a factor of two.

(ii) Follow the instructions in §63.10007(e) and Table 5 to this subpart to convert the test data to the units of the applicable standard.

(3) For Hg, you must conduct a 30-boiler operating day performance test using Method 30B in appendix A-8 to part 60 of this chapter to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within the 10 percent centroidal area of the duct at a location that meets Method 1 in appendix A-1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30-boiler operating day test period. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures), under all process operating conditions. You may use a pair of sorbent traps to sample the stack gas for no more than 10 days.

(i) Depending on whether you intend to assess LEE status for Hg in terms of the lb/TBtu or lb/GWh emission limit in Table 2 to this subpart or in terms of the annual Hg mass emissions limit of 29.0 lb/year, you will have to collect some or all of the following data during the 30-boiler operating day test period (see paragraph (h)(3)(iii) of this section):

(A) Diluent gas (CO_2 or O_2) data, using either Method 3A in appendix A-3 to part 60 of this chapter or a diluent gas monitor that has been certified according to part 75 of this chapter.

(B) Stack gas flow rate data, using either Method 2, 2F, or 2G in appendices A-1 and A-2 to part 60 of this chapter, or a flow rate monitor that has been certified according to part 75 of this chapter.

(C) Stack gas moisture content data, using either Method 4 in appendix A-1 to part 60 of this chapter, or a moisture monitoring system that has been certified according to part 75 of this chapter. Alternatively, an appropriate fuel-specific default moisture value from §75.11(b) of this chapter may be used in the calculations or you may petition the Administrator under §75.66 of this chapter for use of a default moisture value for non-coal-fired units.

(D) Hourly electrical load data (megawatts), from facility records.

(ii) If you use CEMS to measure CO_2 (or O_2) concentration, and/or flow rate, and/or moisture, record hourly average values of each parameter throughout the 30-boiler operating day test period. If you opt to use EPA reference methods rather than CEMS for any parameter, you must perform at least one representative test run on each operating day of the test period, using the applicable reference method.

(iii) Calculate the average Hg concentration, in $\mu g/m^3$ (dry basis), for the 30-boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results. Also calculate, as applicable, the average values of CO_2 or O_2 concentration, stack gas flow rate, stack gas moisture content, and electrical load for the test period. Then:

(A) To express the test results in units of lb/TBtu, follow the procedures in §63.10007(e). Use the average Hg concentration and diluent gas values in the calculations.

(B) To express the test results in units of lb/GWh, use Equations A-3 and A-4 in section 6.2.2 of appendix A to this subpart, replacing the hourly values "C_h", "Q_h", "B_{ws}" and "$(MW)_h$" with the average values of these parameters from the performance test.

(C) To calculate pounds of Hg per year, use one of the following methods:

(*1*) Multiply the average lb/TBtu Hg emission rate (determined according to paragraph (h)(3)(iii)(A) of this section) by the maximum potential annual heat input to the unit (TBtu), which is equal to the maximum rated unit heat input (TBtu/hr) times 8,760 hours. If the maximum rated heat input value is expressed in units of MMBtu/hr, multiply it by 10^{-6} to convert it to TBtu/hr; or

(*2*) Multiply the average lb/GWh Hg emission rate (determined according to paragraph (h)(3)(iii)(B) of this section) by the maximum potential annual electricity generation (GWh), which is equal to the maximum rated electrical output of the unit (GW) times 8,760 hours. If the maximum rated electrical output value is expressed in units of MW, multiply it by 10^{-3} to convert it to GW; or

(*3*) If an EGU has a federally-enforceable permit limit on either the annual heat input or the number of annual operating hours, you may modify the calculations in paragraph (h)(3)(iii)(C)(1) of this section by replacing the maximum potential annual heat input or 8,760 unit operating hours with the permit limit on annual heat input or operating hours (as applicable).

(4) For a group of affected units that vent to a common stack, you may either assess LEE status for the units individually by performing a separate emission test of each unit in the duct leading from the unit to the common stack, or you may perform a single emission test in the common stack. If you choose the common stack testing option, the units in the configuration qualify for LEE status if:

(i) The emission rate measured at the common stack is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section (with some modifications), are less than or equal to 29.0 pounds times the number of units sharing the common stack. Base your calculations on the combined heat input capacity of all units sharing the stack (*i.e.*, either the combined maximum rated value or, if applicable, a lower combined value restricted by permit conditions or operating hours).

(5) For an affected unit with a multiple stack or duct configuration in which the exhaust stacks or ducts are downstream of all emission control devices, you must perform a separate emission test in each stack or duct. The unit qualifies for LEE status if:

(i) The emission rate, based on all test runs performed at all of the stacks or ducts, is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section, are less than or equal to 29.0 pounds. Use the average Hg emission rate from paragraph (h)(5)(i) of this section in your calculations.

(i) *Liquid-oil fuel moisture measurement.* If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraphs (i)(1) through (5) of this section.

(1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or

(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or

(3) Obtain and maintain a fuel moisture certification from your fuel supplier.

(4) Use one of the following methods to determine fuel moisture content:

(i) ASTM D95-05 (Reapproved 2010), "Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation," or

(ii) ASTM D4006-11, "Standard Test Method for Water in Crude Oil by Distillation," including Annex A1 and Appendix A1.

(iii) ASTM D4177-95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," including Annexes A1 through A6 and Appendices X1 and X2, or

(iv) ASTM D4057-06 (Reapproved 2011), "Standard Practice for Manual Sampling of Petroleum and Petroleum Products," including Annex A1.

(5) Use one of the following methods to obtain fuel moisture samples:

(i) ASTM D4177-95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," including Annexes A1 through A6 and Appendices X1 and X2, or

(ii) ASTM D4057-06 (Reapproved 2011), "Standard Practice for Manual Sampling of Petroleum and Petroleum Products," including Annex A1.

(6) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(i) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in §63.10000(c)(2)(iii) or

(ii) Use an HCl CEMS and/or HF CEMS.

(j) Startup and shutdown for coal-fired or solid oil derived-fired units. You must follow the requirements given in Table 3 to this subpart.

(k) You must submit a Notification of Compliance Status summarizing the results of your initial compliance demonstration, as provided in §63.10030.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24084, Apr. 24, 2013]

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§63.10006 When must I conduct subsequent performance tests or tune-ups?

(a) For liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs and IGCC units using PM CPMS to monitor continuous performance with an applicable emission limit as provided for under §63.10000(c), you must conduct all applicable performance tests according to Table 5 to this subpart and §63.10007 at least every year.

(b) For affected units meeting the LEE requirements of §63.10005(h), you must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 and §63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur:

(1) For all pollutant emission limits except for Hg, you must conduct emissions testing quarterly, except as otherwise provided in §63.10021(d)(1).

(2) For Hg, you must install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with appendix A to this subpart, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, you must conduct Hg emissions testing quarterly, except as otherwise provided in §63.10021(d)(1). You must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status.

(c) Except where paragraphs (a) or (b) of this section apply, or where you install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emissions limit, for liquid oil-, solid oil-derived fuel-, coal-fired and IGCC EGUs, you must conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 to this subpart, §63.10007, and §63.10000(c), except as otherwise provided in §63.10021(d)(1).

(d) Except where paragraph (b) of this section applies, for solid oil-derived fuel- and coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, you must conduct all applicable periodic HCl emissions tests according to Table 5 to this subpart and §63.10007 at least quarterly, except as otherwise provided in §63.10021(d)(1).

(e) Except where paragraph (b) of this section applies, for liquid oil-fired EGUs without HCl CEMS, HF CEMS, or HCl and HF CEMS, you must conduct all applicable emissions tests for HCl, HF, or HCl and HF emissions according to Table 5 to this subpart and §63.10007 at least quarterly, except as otherwise provided in §63.10021(d)(1), and conduct site-specific monitoring under a plan as provided for in §63.10000(c)(2)(iii).

(f) Unless you follow the requirements listed in paragraphs (g) and (h) of this section, performance tests required at least every 3 calendar years must be completed within 35 to 37 calendar months after the previous performance test; performance tests required at least every year must be completed within 11 to 13 calendar months after the previous performance test; and performance tests required at least quarterly must be completed within 80 to 100 calendar days after the previous performance test, except as otherwise provided in §63.10021(d)(1).

(g) If you elect to demonstrate compliance using emissions averaging under §63.10009, you must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (f) of this section.

(h) If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if you choose to reapply for LEE status, you must conduct performance tests at the appropriate frequency given in section (c) through (e) of this section for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria.

(i) If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to §63.10021(e).

(1) For EGUs not employing neural network combustion optimization during normal operation, each performance tune-up specified in §63.10021(e) must be no more than 36 calendar months after the previous performance tune-up.

(2) For EGUs employing neural network combustion optimization systems during normal operation, each performance tune-up specified in §63.10021(e) must be no more than 48 calendar months after the previous performance tune-up.

(j) You must report the results of performance tests and performance tune-ups within 60 days after the completion of the performance tests and performance tune-ups. The reports for all subsequent performance tests must include all applicable information required in §63.10031.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24085, Apr. 24, 2013]

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§63.10007 What methods and other procedures must I use for the performance tests?

(a) Except as otherwise provided in this section, you must conduct all required performance tests according to §63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in §63.7(c).

(1) If you use CEMS (Hg, HCl, SO_2, or other) to determine compliance with a 30-boiler operating day rolling average emission limit, you must collect data for all nonexempt unit operating conditions (see §63.10011(g) and Table 3 to this subpart).

(2) If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non Hg metals emissions limit, operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(b) You must conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to this subpart.

(c) If you choose the filterable PM method to comply with the PM emission limit and demonstrate continuous performance using a PM CPMS as provided for in §63.10000(c), you must also establish an operating limit according to §63.10011(b), §63.10023, and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits.

(d) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, you must conduct a minimum of three separate test runs for each performance test, as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 1 or 2 to this subpart. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification.

(e) To use the results of performance testing to determine compliance with the applicable emission limits in Table 1 or 2 to this subpart, proceed as follows:

(1) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

(2) If the limits are expressed in lb/MMBtu or lb/TBtu, you must use the F-factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 in appendix A-7 to part 60 of this chapter. In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Use the following factors to convert the pollutant concentrations measured during the initial performance tests to units of lb/scf, for use in the applicable Method 19 equations:

(i) Multiply SO_2 ppm by 1.66×10^{-7};

(ii) Multiply HCl ppm by 9.43×10^{-8};

(iii) Multiply HF ppm by 5.18×10^{-8};

(iv) Multiply HAP metals concentrations (mg/dscm) by 6.24×10^{-8}; and

(v) Multiply Hg concentrations (µg/scm) by 6.24×10^{-11}.

(3) To determine compliance with emission limits expressed in lb/MWh or lb/GWh, you must first calculate the pollutant mass emission rate during the performance test, in units of lb/h. For Hg, if a CEMS or sorbent trap monitoring system is used, use Equation A-2 or A-3 in appendix A to this subpart (as applicable). In all other cases, use an equation that has the general form of Equation A-2 or A-3, replacing the value of K with 1.66×10^{-7} lb/scf-ppm for SO_2, 9.43×10^{-8} lb/scf-ppm for HCl (if an HCl CEMS is used), 5.18×10^{-8} lb/scf-ppm for HF (if an HF CEMS is used), or 6.24×10^{-8} lb-scm/mg-scf for HAP metals and for HCl and HF (when performance stack testing is used), and defining C_h as the average SO_2, HCl, or HF concentration in ppm, or the average HAP metals concentration in mg/dscm. This calculation requires stack gas volumetric flow rate (scfh) and (in some cases) moisture content data (see §§63.10005(h)(3) and 63.10010). Then, if the applicable emission limit is in units of lb/GWh, use Equation A-4 in appendix A to this subpart to calculate the pollutant emission rate in lb/GWh. In this calculation, define $(M)_h$ as the calculated pollutant mass emission rate for the performance test (lb/h), and define $(MW)_h$ as the average electrical load during the performance test (megawatts). If the applicable emission limit is in lb/MWh rather than lb/GWh, omit the 10^3 term from Equation A-4 to determine the pollutant emission rate in lb/MWh.

(f) Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24085, Apr. 24, 2013]

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§63.10008 [Reserved]

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§63.10009 May I use emissions averaging to comply with this subpart?

(a) *General eligibility.* (1) You may use emissions averaging as described in paragraph (a)(2) of this section as an alternative to meeting the requirements of §63.9991 for filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if:

(i) You have more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control); and

(ii) You use CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance.

(2) You may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory are equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2, according to the procedures in this section. Note that except for Hg emissions from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30 days (rolling daily) using data from CEMS or a combination of data from CEMS and manual performance testing. The averaging time for emissions averaging for Hg from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory is 90 days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of monitoring data and data from manual performance testing. For the purposes of this paragraph, 30- (or 90-day) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group has operated 30 (or 90) days. You must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) days during the preceding 30 (or 90) group boiler days.

(i) You may choose to have your EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross electrical output basis (MWh or GWh, as appropriate for the pollutant).

(ii) You may not mix bases within your EGU emissions averaging group.

(iii) You may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see paragraph (m) of this section).

(b) *Equations.* Use the following equations when performing calculations for your EGU emissions averaging group:

(1) *Group eligibility equations.*

$$WAERm = \frac{\left[\sum_{i=1}^{p} \left[\sum_{i=1}^{n} (Herm_i \times Rmm_i)\right]_p\right] + \sum_{i=1}^{m} (Ter_i \times Rmt_i)}{\left[\sum_{i=1}^{p} \left[\sum_{i=1}^{n} Rmm_i\right]_p\right] + \sum_{i=1}^{m} Rmt_i} \quad (Eq.\ 1a)$$

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Where:

WAERm = Weighted average emissions rate maximum in terms of lb/heat input or lb/gross electrical output,

$Herm_i$ = Hourly emissions rate (e.g., lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring for hour i,

Rmm_i = Maximum rated heat input or gross electrical output of unit i in terms of heat input or gross electrical output,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent test of unit i in terms of lb/heat input or lb/gross electrical output,

Rmt_i = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAERm = \frac{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Herm_i \times Smm_i \times Cfm_i)\right]_p\right] + \sum_{i=1}^{m}(Ter_i \times Smt_i \times Cft_i)}{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n} Smm_i \times Cfm_i\right]_p\right] + \sum_{i=1}^{m} Smt_i \times Cft_i} \quad (Eq.\ 1b)$$

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Where:

variables with similar names share the descriptions for Equation 1a,

Smm_i = maximum steam generation in units of pounds from unit i that uses CEMS or sorbent trap monitoring,

Cfm_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring,

Smt_i = maximum steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(2) Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use equation 2a or 2b to calculate the 30 day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq.\ 2a)$$

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Where:

Her_i = hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hourly rates collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Total heat input or gross electrical output of unit i for the preceding 30-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq.\ 2b)$$

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Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "coal-fired unit not low rank virgin coal" subcategory. Use equation 3a or 3b to calculate the 90-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq.\ 3a)$$

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Where:

Her_i = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 90-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over the 90-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Total heat input or gross electrical output of unit i for the preceding 90-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq.\ 3b)$$

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Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(c) *Separate stack requirements.* For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, you may average filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (d) through (j) of this section.

(d) For each existing EGU in the averaging group:

(1) The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 180 days after April 16, 2015, or the date on which emissions testing done to support your emissions averaging plan is complete (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; or

(2) The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(e) The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified 180 days after April 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier.

(f) Emissions averaging group eligibility demonstration. You must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to paragraph (f)(1) or (2) of this section using the maximum normal operating load of each EGU and the results of the initial performance tests. For this demonstration and prior to submitting your emissions averaging plan, if requested, you must conduct required emissions monitoring for 30 days of boiler operation and any required manual performance testing to calculate an initial weighted average emissions rate in accordance with this section. Should the Administrator require approval, you must submit your proposed emissions averaging plan and supporting data at least 120 days before April 16, 2015. If the Administrator requires approval of your plan, you may not begin using emissions averaging until the Administrator approves your plan.

(1) You must use Equation 1a in paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 to this subpart.

(2) If you are not capable of monitoring heat input or gross electrical output, and the EGU generates steam for purposes other than generating electricity, you may use Equation 1b of this section as an alternative to using Equation 1a of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 to this subpart.

(g) You must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 day rolling average (90 day rolling average for Hg) basis according to paragraphs (g)(1) through (2) of this section. The first averaging period begins on 30 (or 90 for Hg) days after February 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross electrical output for each existing unit participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input or gross electrical output, you may use Equation 2b or 3b of paragraph (b) of this section as an alternative to using Equation 2a of paragraph (b) of this section to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

(h) *CEMS (or sorbent trap monitoring) use.* If an EGU in your emissions averaging group uses CEMS (or a sorbent trap monitor for Hg emissions) to demonstrate compliance, you must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate.

(i) *Emissions testing.* If you use manual emissions testing to demonstrate compliance for one or more EGUs in your emissions averaging group, you must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. You may use CEMS or sorbent trap data in combination with data from the most recent manual performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate.

(j) *Emissions averaging plan.* You must develop an implementation plan for emissions averaging according to the following procedures and requirements in paragraphs (j)(1) and (2) of this section.

(1) You must include the information contained in paragraphs (j)(1)(i) through (v) of this section in your implementation plan for all the emissions units included in an emissions averaging:

(i) The identification of all existing EGUs in the emissions averaging group, including for each either the applicable HAP emission level or the control technology installed as of 180 days after February 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; and the date on which you are requesting emissions averaging to commence;

(ii) The process weighting parameter (heat input, gross electrical output, or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission EGU in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple EGUs, you must identify each EGU;

(iv) The means of measurement (e.g., CEMS, sorbent trap monitoring, manual performance test) of filterable PM, SO_2, HF, HCl, individual or total non-Hg HAP metals, or Hg emissions in accordance with the requirements in §63.10007 and to be used in the emissions averaging calculations; and

(v) A demonstration that emissions averaging can produce compliance with each of the applicable emission limit(s) in accordance with paragraph (b)(1) of this section.

(2) If the Administrator requests you to submit the plan for review and approval, you must submit a complete implementation plan at least 120 days before April 16, 2015. If the Administrator requests you to submit the plan for review and approval, you must receive approval before initiating emissions averaging.

(i) The Administrator shall use following criteria in reviewing and approving or disapproving the plan:

(A) Whether the content of the plan includes all of the information specified in paragraph (j)(1) of this section; and

(B) Whether the plan presents information sufficient to determine that compliance will be achieved and maintained.

(ii) The Administrator shall not approve an emissions averaging implementation plan containing any of the following provisions:

(A) Any averaging between emissions of different pollutants or between units located at different facilities; or

(B) The inclusion of any emissions unit other than an existing unit in the same subcategory.

(k) *Common stack requirements.* For a group of two or more existing affected units, each of which vents through a single common stack, you may average emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraph (l) or (m) of this section.

(l) For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(m) For all other groups of units subject to paragraph (k) of this section, you may elect to conduct manual performance tests according to procedures specified in §63.10007 in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other nonaffected units all vent to the common stack, you must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, you may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. You may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis.

(n) Combination requirements. The common stack of a group of two or more existing EGUs in the same subcategory subject to paragraph (k) of this section may be treated as a single stack for purposes of paragraph (c) of this section and included in an emissions averaging group subject to paragraph (c) of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23403, Apr. 19, 2012; 78 FR 24085, Apr. 24, 2013]

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§63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

(1) *Single unit-single stack configurations.* For an affected unit that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

(2) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, you shall either:

(i) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the duct leading to the common stack from each unit; or

(ii) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the common stack.

(3) *Unit(s) utilizing common stack with non-affected unit(s).*

(i) When one or more affected units shares a common stack with one or more non-affected units, you shall either:

(A) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the ducts leading to the common stack from each affected unit; or

(B) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in this section in the common stack and attribute all of the emissions measured at the common stack to the affected unit(s).

(ii) If you choose the common stack monitoring option:

(A) For each hour in which valid data are obtained for all parameters, you must calculate the pollutant emission rate and

(B) You must assign the calculated pollutant emission rate to each unit that shares the common stack.

(4) *Unit with a main stack and a bypass stack.* If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack, or, if it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall install a CEMS only on the main stack and count bypass hours of deviation from the monitoring requirements.

(5) *Unit with a common control device with multiple stack or duct configuration.* If the flue gases from an affected unit, which is configured such that emissions are controlled with a common control device or series of control devices, are discharged to the atmosphere through more than one stack or are fed into a single stack through two or more ducts, you may:

(i) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the multiple stacks;

(ii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the ducts that feed into the stack;

(iii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in one of the multiple stacks or ducts and monitor the flows and dilution rates in all multiple stacks or ducts in order to determine total exhaust gas flow rate and pollutant mass emissions rate in accordance with the applicable limit; or

(iv) In the case of multiple ducts feeding into a single stack, install CEMS, PM CPMS, and sorbent trap monitoring systems in the single stack as described in paragraph (a)(1) of this section.

(6) *Unit with multiple parallel control devices with multiple stacks.* If the flue gases from an affected unit, which is configured such that emissions are controlled with multiple parallel control devices or multiple series of control devices are discharged to the atmosphere through more than one stack, you shall install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in each of the multiple stacks. You shall calculate hourly flow-weighted average pollutant emission rates for the unit as follows:

(i) Calculate the pollutant emission rate at each stack or duct for each hour in which valid data are obtained for all parameters;

(ii) Multiply each calculated hourly pollutant emission rate at each stack or duct by the corresponding hourly stack gas flow rate at that stack or duct;

(iii) Sum the products determined under paragraph (a)(6)(ii) of this section; and

(iv) Divide the result obtained in paragraph (a)(6)(iii) of this section by the total hourly stack gas flow rate for the unit, summed across all of the stacks or ducts.

(b) If you use an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, *i.e.,* at the outlet of the EGU, downstream of all emission control devices. You must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O_2 or CO_2 data in the emissions calculations; do not use part 75 substitute data values.

(c) If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.

(d) If you are required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 1 of 2 to this subpart, you must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, for coal-fired units, you may use appropriate fuel-specific default moisture values from §75.11(b) of this chapter to estimate the moisture content of the stack gas or you may petition the Administrator under §75.66 of this chapter for use of a default moisture value for non-coal-fired units. If you install and operate a moisture monitoring system, do not use substitute moisture data in the emissions calculations.

(e) If you use an HCl and/or HF CEMS, you must install, certify, operate, maintain, and quality-assure the data from the monitoring system in accordance with appendix B to this subpart. Calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of appendix B to this subpart).

(f)(1) If you use an SO_2 CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.

(2) For on-going QA, the SO_2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

(3) Calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid SO_2 emission rates in the preceding 30 boiler operating days.

(4) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

(g) If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You must calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of appendix A to this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit, you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section.

(1) Install, calibrate, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.10000(d), and meet the requirements in paragraphs (h)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal.

(ii) The PM CPMS must have a cycle time (*i.e.*, period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable, at a minimum, of detecting and responding to particulate matter concentrations of 0.5 mg/acm.

(2) For a new unit, complete the initial PM CPMS performance evaluation no later than October 13, 2012 or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than October 13, 2015.

(3) Collect PM CPMS hourly average output data for all boiler operating hours except as indicated in paragraph (h)(5) of this section. Express the PM CPMS output as milliamps, PM concentration, or other raw data signal value.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CPMS output collected during all nonexempt boiler operating hours data (e.g., milliamps, PM concentration, raw data signal).

(5) You must collect data using the PM CPMS at all times the process unit is operating and at the intervals specified in paragraph (h)(1)(ii) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), and any scheduled maintenance as defined in your site-specific monitoring plan.

(6) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(i) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities conducted during monitoring system malfunctions are not used in calculations (report any such periods in your annual deviation report);

(ii) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods are not used in calculations (report emissions or operating levels and report any such periods in your annual deviation report);

(iii) Any data recorded during periods of startup or shutdown.

(7) You must record and make available upon request results of PM CPMS system performance audits, as well as the dates and duration of periods from when the PM CPMS is out of control until completion of the corrective actions necessary to return the PM CPMS to operation consistent with your site-specific monitoring plan.

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits, you may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (i)(1) through (5) of this section. The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2 to this subpart.

(1) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using Method 5 at Appendix A-3 to part 60 of this chapter and ensuring that the front half filter temperature shall be 160° ± 14 °C (320° ± 25 °F). The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(2) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(i) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(ii) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(3) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours.

(5) You must collect data using the PM CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(ii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(j) You may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with §63.7(f) as an alternative to the performance test method specified in this rule. If approved to use a HAP metals CEMS, the compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2. If approved, you may choose to install, certify, operate, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in paragraphs (j)(1) through (5) of this section.

(1)(i) Install and certify your HAP metals CEMS according to the procedures and requirements in your approved site-specific test plan as required in §63.7(e). The reportable measurement output from the HAP metals CEMS must be expressed in units of the applicable emissions limit (*e.g.,* lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

(ii) Operate and maintain your HAP metals CEMS according to the procedures and criteria in your site specific performance evaluation and quality control program plan required in §63.8(d).

(2) Collect HAP metals CEMS hourly average output data for all boiler operating hours except as indicated in section (j)(4) of this section.

(3) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average HAP metals CEMS output data collected during all nonexempt boiler operating hours data.

(4) You must collect data using the HAP metals CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your emission limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(ii) You must record and make available upon request results of HAP metals CEMS system performance audits, dates and duration of periods when the HAP metals CEMS is out of control to completion of the corrective actions necessary to return the HAP metals CEMS to operation consistent with your site-specific performance evaluation and quality control program plan.

(k) If you demonstrate compliance with the HCl and HF emission limits for a liquid oil-fired EGU by conducting quarterly testing, you must also develop a site-specific monitoring plan as provided for in §63.10000(c)(2)(iii) and Table 7 to this subpart.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 78 FR 24086, Apr. 24, 2013]

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§63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

(a) You must demonstrate initial compliance with each emissions limit that applies to you by conducting performance testing.

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance, or if, for a liquid oil-fired unit, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with Table 4 to this subpart, §63.10007, and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (*i.e.*, tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit.

(c)(1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (e.g., Hg or HCl) directly, the first 30-boiler operating day (or, if alternate emissions averaging is used for Hg, the 90-boiler operating day) rolling average emission rate obtained with certified CEMS after the applicable date in §63.9984 (or, if applicable, prior to that date, as described in §63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.

(2) For a unit that uses a CEMS to measure SO_2 or PM emissions for initial compliance, the first 30 boiler operating day average emission rate obtained with certified CEMS after the applicable date in §63.9984 (or, if applicable, prior to that date, as described in §63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable SO_2 or filterable PM emission limit in Table 1 or 2 to this subpart.

(d) For candidate LEE units, use the results of the performance testing described in §63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 1 or 2 to this subpart and to determine whether the unit qualifies for LEE status.

(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, according to §63.10030(e).

(f)(1) You must determine the fuel whose combustion produces the least uncontrolled emissions, *i.e.*, the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown.

(2) Your cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account.

(g) You must follow the startup or shutdown requirements given in Table 3 for each coal-fired, liquid oil-fired, and solid oil-derived fuel-fired EGU.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012]

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CONTINUOUS COMPLIANCE REQUIREMENTS

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§63.10020 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.10000(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see §63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during EGU startup or shutdown or monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation from the monitoring requirements.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012]

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§63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

(a) You must demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you, according to the monitoring specified in Tables 6 and 7 to this subpart and paragraphs (b) through (g) of this section.

(b) Except as otherwise provided in §63.10020(c), if you use a CEMS to measure SO_2, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30- (or, if applicable, 90-) boiler operating day rolling average.

$$Boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n} \quad (Eq.\ 8)$$

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Where:

Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

(c) If you use a PM CPMS data to measure compliance with an operating limit in Table 4 to this subpart, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 9 to determine the 30 boiler operating day average.

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n} \quad (Eq.\ 9)$$

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Where:

Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30 boiler operating days.

(1) For any exceedance of the 30-boiler operating day PM CPMS average value from the established operating parameter limit for an EGU subject to the emissions limits in Table 1 to this subpart, you must:

(i) Within 48 hours of the exceedance, visually inspect the air pollution control device (APCD);

(ii) If the inspection of the APCD identifies the cause of the exceedance, take corrective action as soon as possible, and return the PM CPMS measurement to within the established value; and

(iii) Within 45 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct any additional testing for any exceedances that occur between the time of the original exceedance and the PM emissions compliance test required under this paragraph.

(2) PM CPMS exceedances of the operating limit for an EGU subject to the emissions limits in Table 1 of this subpart leading to more than four required performance tests in a 12-month period (rolling monthly) constitute a separate violation of this subpart.

(d) If you use quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 1 or 2 to this subpart, you

(1) May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year.

(2) Must conduct the performance test as defined in Table 5 to this subpart and calculate the results of the testing in units of the applicable emissions standard; and

(3) Must conduct site-specific monitoring for a liquid oil-fired unit to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of §63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in §63.10020(a).

(e) If you must conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section, perform the first tune-up as part of your initial compliance demonstration. Notwithstanding this requirement, you may delay the first burner inspection until the next scheduled unit outage provided you meet the requirements of §63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months.

(1) As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

(i) Burner or combustion control component parts needing replacement that affect the ability to optimize NO_X and CO must be installed within 3 calendar months after the burner inspection,

(ii) Burner or combustion control component parts that do not affect the ability to optimize NO_X and CO may be installed on a schedule determined by the operator;

(2) As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

(3) As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

(4) As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

(5) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O_2 probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

(6) Optimize combustion to minimize generation of CO and NO_X. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO_X optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

(7) While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO_X in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NO_X and O_2 monitors for this measurement. EGU's employing neural network optimization systems need only

provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;

(8) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including:

(i) The concentrations of CO and NO_X in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and

(9) Report the dates of the initial and subsequent tune-ups as follows:

(i) If the first required tune-up is performed as part of the initial compliance demonstration, report the date of the tune-up in hard copy (as specified in §63.10030) and electronically (as specified in §63.10031). Report the date of each subsequent tune-up electronically (as specified in §63.10031).

(ii) If the first tune-up is not conducted as part of the initial compliance demonstration, but is postponed until the next unit outage, report the date of that tune-up and all subsequent tune-ups electronically, in accordance with §63.10031.

(f) You must submit the reports required under §63.10031 and, if applicable, the reports required under appendices A and B to this subpart. The electronic reports required by appendices A and B to this subpart must be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in §63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under §63.10031.

(g) You must report each instance in which you did not meet an applicable emissions limit or operating limit in Tables 1 through 4 to this subpart or failed to conduct a required tune-up. These instances are deviations from the requirements of this subpart. These deviations must be reported according to §63.10031.

(h) You must keep records as specified in §63.10032 during periods of startup and shutdown.

(i) You must provide reports as specified in §63.10031 concerning activities and periods of startup and shutdown.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 78 FR 24086, Apr. 24, 2013]

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§63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (3) of this section.

(1) For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.10009(f) and (g);

(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test;

(3) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (3) of this section is a deviation.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012]

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§63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

(a) During the initial performance test or any such subsequent performance test that demonstrates compliance with the filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 1 or 2, record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for three 3-hour test runs).

(b) Determine your operating limit as provided in paragraph (b)(1) or (b)(2) of this section. You must verify an existing or establish a new operating limit after each repeated performance test.

(1) For an existing EGU, determine your operating limit based on the highest 1-hour average PM CPMS output value recorded during the performance test.

(2) For a new EGU, determine your operating limit as follows.

(i) If your PM performance test demonstrates your PM emissions do not exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. Calculate the operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 compliance test with the procedures in (b)(2)(i)(A) through (D) of this section.

(A) Determine your PM CPMS instrument zero output with one of the following procedures.

(*1*) Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*2*) Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*3*) The zero point can also can be obtained by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*4*) If none of the steps in paragraphs (A)(*1*) through (*3*) of this section are possible, you must use a zero output value provided by the manufacturer.

(B) Determine your PM CPMS instrument average (*x*) in milliamps, and the average of your corresponding three PM compliance test runs (*y*), using equation 10.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_i, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_i \qquad \text{(Eq. 10)}$$

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Where:

X_i = the PM CPMS data points for run i of the performance test,

Y_i = the PM emissions value (in lb/MWh) for run i of the performance test, and

n = the number of data points.

(C) With your PM CPMS instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM emissions value (in lb/MWh) from your compliance runs, determine a relationship of PM lb/MWh per milliamp with equation 11.

$$R = \frac{y}{(x - z)} \quad \text{(Eq. 11)}$$

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Where:

R = the relative PM lb/MWh per milliamp for your PM CPMS,

y = the three run average PM lb/MWh,

x = the three run average milliamp output from your PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (b)(2)(i)(A) of this section.

(D) Determine your source specific 30-day rolling average operating limit using the PM lb/MWh per milliamp value from equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_L = z + \frac{(0.75 \times L)}{R} \quad \text{(Eq. 12)}$$

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Where:

O_L = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps,

L = your source PM emissions limit in lb/MWh,

z = your instrument zero in milliamps, determined from (b)(2)(i)(A) of this section, and

R = the relative PM lb/MWh per milliamp for your PM CPMS, from equation 11.

(ii) If your PM compliance test demonstrates your PM emissions exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish your operating limit.

(A) Determine your operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13.

$$O_h = \frac{1}{n} \sum_{i=1}^{n} X_i \quad \text{(Eq. 13)}$$

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Where:

X_i = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

(iii) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(iv) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(v) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs.

(vi) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signal corresponding to each PM compliance test run.

(c) You must operate and maintain your process and control equipment such that the 30 operating day average PM CPMS output does not exceed the operating limit determined in paragraphs (a) and (b) of this section.

[77 FR 9464, Feb. 16, 2012, as amended at 78 FR 24086, Apr. 24, 2013]

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NOTIFICATION, REPORTS, AND RECORDS

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§63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you startup your EGU that is an affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.

(c) As specified in §63.9(b)(4) and (b)(5), if you startup your new or reconstructed EGU that is an affected source on or after April 16, 2012, you must submit an Initial Notification not later than 15 days after the actual date of startup of the EGU that is an affected source.

(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) When you are required to conduct an initial compliance demonstration as specified in §63.10011(a), you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (7), as applicable.

(1) A description of the affected source(s) including identification of which subcategory the source is in, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (e.g., use of PM CPMS); CEMS; or a sorbent trap monitoring system.

(4) Identification of whether you plan to demonstrate compliance by emissions averaging.

(5) A signed certification that you have met all applicable emission limits and work practice standards.

(6) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation in the Notification of Compliance Status report.

(7) In addition to the information required in §63.9(h)(2), your notification of compliance status must include the following:

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with §63.10006(b), the date of the last three stack tests, a comparison of the emission level you achieved in the last three stack tests to the 50 percent emission limit threshold required in §63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(ii) Certifications of compliance, as applicable, and must be signed by a responsible official stating:

(A) "This EGU complies with the requirements in §63.10021(a) to demonstrate continuous compliance." and

(B) "No secondary materials that are solid waste were combusted in any affected unit."

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012; 78 FR 24087, Apr. 24, 2013]

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§63.10031 What reports must I submit and when?

(a) You must submit each report in Table 8 to this subpart that applies to you. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also submit the electronic reports required under appendix A and/or appendix B to the subpart, at the specified frequency.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 8 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.9984 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.9984.

(2) The first compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.9984.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (4) of this section.

(1) The information required by the summary report located in 63.10(e)(3)(vi).

(2) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(3) Indicate whether you burned new types of fuel during the reporting period. If you did burn new types of fuel you must include the date of the performance test where that fuel was in use.

(4) Include the date of the most recent tune-up for each unit subject to the requirement to conduct a performance tune-up according to §63.10021(e). Include the date of the most recent burner inspection if it was not done every 36 (or 48) months and was delayed until the next scheduled unit shutdown.

(d) For each excess emissions occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in §63.10 (e)(3)(v) in the compliance report specified in section (c).

(e) Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 8 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(f) As of January 1, 2012, and within 60 days after the date of completing each performance test, you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(1) Within 60 days after the date of completing each CEMS (SO_2, PM, HCl, HF, and Hg) performance evaluation test, as defined in §63.2 and required by this subpart, you must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). The RATA data shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (*http://www.epa.gov/ttn/chief/ert/index.html*). Only RATA data compounds listed on the ERT Web site are subject to this requirement. Owners or operators who claim that some of the information being submitted for RATAs is confidential business information (CBI) shall submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. The compact disk or other commonly used electronic storage media shall be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. At the discretion of the delegated authority, owners or operators shall also submit these RATAs to the delegated authority in the format specified by the delegated authority. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in §63.2 and as required in this chapter.

(2) For a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st, you must submit quarterly reports to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format. For

each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS.

(3) Reports for an SO_2 CEMS, a Hg CEMS or sorbent trap monitoring system, an HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in Appendices A and B to this subpart and §63.10021(f).

(4) Submit the compliance reports required under paragraphs (c) and (d) of this section and the notification of compliance status required under §63.10030(e) to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format.

(5) All reports required by this subpart not subject to the requirements in paragraphs (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f)(1), (2), and (3) of this section in paper format.

(g) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23404, Apr. 19, 2012]

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§63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also keep the records required under appendix A and/or appendix B to this subpart.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in §63.10(b)(2)(viii).

(b) For each CEMS and CPMS, you must keep records according to paragraphs (b)(1) through (4) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in §63.8 (d)(3).

(3) Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).

(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 7 to this subpart including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each EGU subject to an emission limit, you must also keep the records in paragraphs (d) (1) through (3) of this section.

(1) You must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), you must keep a record which documents how the fuel satisfies the requirements of the petition process.

(3) For an EGU that qualifies as an LEE under §63.10005(h), you must keep annual records that document that your emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.

(e) If you elect to average emissions consistent with §63.10009, you must additionally keep a copy of the emissions averaging implementation plan required in §63.10009(g), all calculations required under §63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with §63.10022.

(f) You must keep records of the occurrence and duration of each startup and/or shutdown.

(g) You must keep records of the occurrence and duration of each malfunction of an operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment.

(h) You must keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(i) You must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.

(j) If you elect to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, you must keep records of the type(s) and amount(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met.

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§63.10033 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

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OTHER REQUIREMENTS AND INFORMATION

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§63.10040 What parts of the General Provisions apply to me?

Table 9 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

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§63.10041 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency; moreover, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate, with respect to any failure by any person to comply with any provision of this subpart.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in §63.9991(a) and (b) under §63.6(g).

(2) Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90, approval of minor and intermediate changes to monitoring performance specifications/procedures in Table 5 where the monitoring serves as the performance test method (see definition of "test method" in §63.2.

(3) Approval of major changes to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major change to recordkeeping and reporting under §63.10(e) and as defined in §63.90.

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§63.10042 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in §63.2 (the General Provisions), and in this section as follows:

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Anthracite coal means solid fossil fuel classified as anthracite coal by American Society of Testing and Materials (ASTM) Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see §63.14).

Bituminous coal means coal that is classified as bituminous according to ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see §63.14).

Boiler operating day means a 24-hour period between midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for the fuel to be combusted the entire 24-hour period.

Capacity factor for a liquid oil-fired EGU means the total annual heat input from oil divided by the product of maximum hourly heat input for the EGU, regardless of fuel, multiplied by 8,760 hours.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see §63.14), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (not meeting the definition of natural gas), solvent-refined coal, coal-oil mixtures, and coal-water mixtures, are considered "coal" for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns coal for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Coal refuse means any by-product of coal mining, physical coal cleaning, and coal preparation operations (e.g., culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

Cogeneration means a steam-generating unit that simultaneously produces both electrical and useful thermal (or mechanical) energy from the same primary energy source.

Cogeneration unit means a stationary, fossil fuel-fired EGU meeting the definition of "fossil fuel-fired" or stationary, integrated gasification combined cycle:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

Combined-cycle gas stationary combustion turbine means a stationary combustion turbine system where heat from the turbine exhaust gases is recovered by a waste heat boiler.

Common stack means the exhaust of emissions from two or more affected units through a single flue.

Continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located in the continental United States.

Deviation. (1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, work practice standard, or monitoring requirement; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM Method D396-10, "Standard Specification for Fuel Oils" (incorporated by reference, see §63.14).

Dry flue gas desulfurization technology, or *dry FGD,* or *spray dryer absorber* (*SDA*), or *spray dryer,* or *dry scrubber* means an add-on air pollution control system located downstream of the steam generating unit that injects a dry alkaline sorbent (dry sorbent injection) or sprays an alkaline sorbent slurry (spray dryer) to react with and neutralize acid gases such as SO_2 and HCl in the exhaust stream forming a dry powder material. Alkaline sorbent injection systems in fluidized bed combustors (FBC) or circulating fluidized bed (CFB) boilers are included in this definition.

Dry sorbent injection (DSI) means an add-on air pollution control system in which sorbent (e.g., conventional activated carbon, brominated activated carbon, Trona, hydrated lime, sodium carbonate, etc.) is injected into the flue gas steam upstream of a PM control device to react with and neutralize acid gases (such as SO_2 and HCl) or Hg in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device.

Electric Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included) for the purpose of powering a generator to produce electricity or electricity and other thermal energy.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Emission limitation means any emissions limit, work practice standard, or operating limit.

Excess emissions means, with respect to this subpart, results of any required measurements outside the applicable range (e.g., emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60, 61, and 63; requirements within any applicable state implementation plan; and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Flue gas desulfurization system means any add-on air pollution control system located downstream of the steam generating unit whose purpose or effect is to remove at least 50 percent of the SO_2 in the exhaust gas stream.

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of combusting more than 25 MW of fossil fuels. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, and residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Fluidized bed boiler, or *fluidized bed combustor,* or *circulating fluidized boiler*, or *CFB* means a boiler utilizing a fluidized bed combustion process.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles which are maintained in a mobile suspension by the upward flow of air and combustion products.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, solid oil-derived gas, refinery gas, and biogas.

Generator means a device that produces electricity.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical output, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls), or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in an EGU (synthetic gas for an IGCC) and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, etc.

Integrated gasification combined cycle electric utility steam generating unit or *IGCC* means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year in a combined-cycle gas turbine. No solid coal or solid oil-derived fuel is directly burned in the unit during operation.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite coal means coal that is classified as lignite A or B according to ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see §63.14).

Limited-use liquid oil-fired subcategory means an oil-fired electric utility steam generating unit with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing April 16, 2015.

Liquid fuel includes, but is not limited to, distillate oil and residual oil.

Monitoring system malfunction or out of control period means any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 Btu per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Natural gas-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Non-continental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Non-continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located outside the continental United States.

Non-mercury (Hg) HAP metals means Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se).

Oil means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, solid oil-derived fuel (e.g., petroleum coke) and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

Oil-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Particulate matter or *PM* means any finely divided solid material as measured by the test methods specified under this subpart, or an alternative method.

Pulverized coal (PC) boiler means an EGU in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the EGU where it is fired in suspension.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by ASTM Method D396-10, "Standard Specification for Fuel Oils" (incorporated by reference, see §63.14).

Responsible official means responsible official as defined in 40 CFR 70.2.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use), or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler.

Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use).

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included).

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit undergrate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. There are two general types of stokers: underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers.

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to ASTM Method D388-05, "Standard Classification of Coals by Rank" (incorporated by reference, see §63.14).

Unit designed for coal ≥ 8,300 Btu/lb subcategory means any coal-fired EGU that is not a coal-fired EGU in the "unit designed for low rank virgin coal" subcategory.

Unit designed for low rank virgin coal subcategory means any coal-fired EGU that is designed to burn and that is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed to burn solid oil-derived fuel subcategory means any oil-fired EGU that burns solid oil-derived fuel.

Voluntary consensus standards or VCS mean technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. states, e.g., California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, e.g., Department of Defense (DOD) and

Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within an EPA rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-VCS methods.

Wet flue gas desulfurization technology, or *wet FGD, or wet scrubber* means any add-on air pollution control device that is located downstream of the steam generating unit that mixes an aqueous stream or slurry with the exhaust gases from an EGU to control emissions of PM and/or to absorb and neutralize acid gases, such as SO_2 and HCl.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to CAA section 112(h).

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23405, Apr. 19, 2012; 78 FR 24087, Apr. 24, 2013]

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TABLES TO SUBPART UUUUU OF PART 63

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Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs

As stated in §63.9991, you must comply with the following applicable emission limits:

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM)	9.0E-2 lb/MWh[1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	
	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run.
			For ASTM D6348-03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
		9.0E-2 lb/MWh[1]	

2. Coal-fired units low rank virgin coal	a. Filterable particulate matter (PM)		Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	4.0E-4 lb/GWh	
	Chromium (Cr)	7.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	5.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	1.0E-2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run.
			For ASTM D6348-03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E-2 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM)	7.0E-2 lb/MWh[4] 9.0E-2 lb/MWh[5]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E-2 lb/GWh	
	Arsenic (As)	2.0E-2 lb/GWh	
	Beryllium (Be)	1.0E-3 lb/GWh	
	Cadmium (Cd)	2.0E-3 lb/GWh	
	Chromium (Cr)	4.0E-2 lb/GWh	
	Cobalt (Co)	4.0E-3 lb/GWh	
	Lead (Pb)	9.0E-3 lb/GWh	
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	7.0E-2 lb/GWh	
	Selenium (Se)	3.0E-1 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run.

			For ASTM D6348-03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	4.0E-1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-1 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E-4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E-2 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	5.0E-4 lb/GWh	
	Cadmium (Cd)	2.0E-4 lb/GWh	
	Chromium (Cr)	2.0E-2 lb/GWh	
	Cobalt (Co)	3.0E-2 lb/GWh	
	Lead (Pb)	8.0E-3 lb/GWh	
	Manganese (Mn)	2.0E-2 lb/GWh	
	Nickel (Ni)	9.0E-2 lb/GWh	
	Selenium (Se)	2.0E-2 lb/GWh	
	Mercury (Hg)	1.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < $^{1/2}$ the standard.
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run.
			For ASTM D6348-03[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run.
			For ASTM D6348-03[2] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	2.0E-1 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	7.0E-3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	6.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-3 lb/GWh	
	Cadmium (Cd)	2.0E-3 lb/GWh	

	Chromium (Cr)	2.0E-2 lb/GWh	
	Cobalt (Co)	3.0E-1 lb/GWh	
	Lead (Pb)	3.0E-2 lb/GWh	
	Manganese (Mn)	1.0E-1 lb/GWh	
	Nickel (Ni)	4.1E0 lb/GWh	
	Selenium (Se)	2.0E-2 lb/GWh	
	Mercury (Hg)	4.0E-4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < 1/2 the standard.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run.
			For ASTM D6348-03[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	5.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run.
			For ASTM D6348-03[2] or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM)	3.0E-2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-3 lb/GWh	
	Arsenic (As)	3.0E-3 lb/GWh	
	Beryllium (Be)	6.0E-4 lb/GWh	
	Cadmium (Cd)	7.0E-4 lb/GWh	
	Chromium (Cr)	6.0E-3 lb/GWh	
	Cobalt (Co)	2.0E-3 lb/GWh	
	Lead (Pb)	2.0E-2 lb/GWh	
	Manganese (Mn)	7.0E-3 lb/GWh	
	Nickel (Ni)	4.0E-2 lb/GWh	
	Selenium (Se)	6.0E-3 lb/GWh	
	b. Hydrogen chloride (HCl)	4.0E-4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run.
			For ASTM D6348-03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E-3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

[1]Gross electric output.

[2]Incorporated by reference, see §63.14.

[3]You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO_2 CEMS installed.

[4]Duct burners on syngas; gross electric output.

[5]Duct burners on natural gas; gross electric output.

[78 FR 24087, Apr. 24, 2013]

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Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

As stated in §63.9991, you must comply with the following applicable emission limits:[1]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh.[2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh.	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh.	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run.
			For ASTM D6348-03[3] or Method 320, sample for a minimum of 1 hour.
	OR		
			SO_2 CEMS.

	Sulfur dioxide (SO_2)[4]	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh.	
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E-2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh.[2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh.	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh.	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run.
			For ASTM D6348-03[3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[4]	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	4.0E0 lb/TBtu or 4.0E-2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM)	4.0E-2 lb/MMBtu or 4.0E-1 lb/MWh.[2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E-5 lb/MMBtu or 5.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	

	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Beryllium (Be)	1.0E-1 lb/TBtu or 1.0E-3 lb/GWh.	
	Cadmium (Cd)	1.5E-1 lb/TBtu or 2.0E-3 lb/GWh.	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E-2 lb/GWh.	
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Lead (Pb)	1.9E+2 lb/TBtu or 1.8E0 lb/GWh.	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh.	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E-2 lb/GWh.	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh.	
	b. Hydrogen chloride (HCl)	5.0E-4 lb/MMBtu or 5.0E-3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run.
			For ASTM D6348-03[3] or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E-2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh.[2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	8.0E-4 lb/MMBtu or 8.0E-3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 1 dscm per run.
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E-1 lb/GWh.	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh.	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh.	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 2.0E-3 lb/GWh.	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E-2 lb/GWh.	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E-1 lb/GWh.	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E-2 lb/GWh.	

	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E-1 lb/GWh.	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh.	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E-2 lb/GWh.	
	Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh.	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <1/2; the standard.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 1.0E-2 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per Run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03[3] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E-4 lb/MMBtu or 4.0E-3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run.
			For ASTM D6348-03[3] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units)	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh.[2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	6.0E-4 lb/MMBtu or 7.0E-3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E-2 lb/GWh.	
	Beryllium (Be)	6.0E-1 lb/TBtu or 3.0E-3 lb/GWh.	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh.	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E-1 lb/GWh.	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh.	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E-2 lb/GWh.	
	Manganese (Mn)	2.0E+1 lb/TBtu or 3.0E-1 lb/GWh.	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh.	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E-1 lb/GWh.	
	Mercury (Hg)	4.0E-2 lb/TBtu or 4.0E-4 lb/GWh.	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg

			concentration should nominally be <1/2; the standard.
	b. Hydrogen chloride (HCl)	2.0E-4 lb/MMBtu or 2.0E-3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-03[3] or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF)	6.0E-5 lb/MMBtu or 5.0E-4 lb/MWh.	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348-03[3] or Method 320, sample for a minimum of 2 hours.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM)	8.0E-3 lb/MMBtu or 9.0E-2 lb/MWh.[2]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-5 lb/MMBtu or 6.0E-1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals	Collect a minimum of 3 dscm per run.	
	Antimony (Sb)	8.0E-1 lb/TBtu or 7.0E-3 lb/GWh.	
	Arsenic (As)	3.0E-1 lb/TBtu or 5.0E-3 lb/GWh.	
	Beryllium (Be)	6.0E-2 lb/TBtu or 5.0E-4 lb/GWh.	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 4.0E-3 lb/GWh.	
	Chromium (Cr)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh.	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh.	
	Lead (Pb)	8.0E-1 lb/TBtu or 2.0E-2 lb/GWh.	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E-2 lb/GWh.	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E-1 lb/GWh.	
	Selenium (Se)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh.	
	b. Hydrogen chloride (HCl)	5.0E-3 lb/MMBtu or 8.0E-2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run.
			For ASTM D6348-03[3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[4]	3.0E-1 lb/MMBtu or 2.0E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh.	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or Sorbent trap monitoring system only.

[1] For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.

[2] Gross electric output.

[3] Incorporated by reference, see §63.14.

[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

[77 FR 23405, Apr. 19, 2012]

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Table 3 to Subpart UUUUU of Part 63—Work Practice Standards

As stated in §§63.9991, you must comply with the following applicable work practice standards:

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in §63.10021(e).
2. A new or reconstructed EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in §63.10021(e).
3. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during startup	You must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels, either natural gas or distillate oil or a combination of clean fuels for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in §63.10011(g) and §63.10021(h) and (i).
4. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during shutdown	You must operate all CMS during shutdown. Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use) or at the point of no fuel being fired in the boiler. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler. During shutdown, you must operate all applicable control technologies while firing coal, residual oil, or solid oil-derived fuel. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in §63.10011(g) and §63.10021(h) and (i).

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Table 4 to Subpart UUUUU of Part 63—Operating Limits for EGUs

As stated in §63.9991, you must comply with the applicable operating limits:

If you demonstrate compliance using . . .	You must meet these operating limits . . .

1. PM CPMS for an existing EGU	Maintain the 30-boiler operating day rolling average PM CPMS output at or below the highest 1-hour average measured during the most recent performance test demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation (s).
2. PM CPMS for a new EGU	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of §63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

[78 FR 24090, Apr. 24, 2013]

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Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements

As stated in §63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:[1]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit ...	Using[2] . . .
1. Filterable Particulate matter (PM)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the filterable PM concentration	Method 5 at Appendix A-3 to part 60 of this chapter.
			For positive pressure fabric filters, Method 5D at Appendix A-3 to part 60 of this chapter for filterable PM emissions.
			Note that the Method 5 front half temperature shall be 160 ° ± 14 °C (320 ° ± 25 °F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see §63.10007(e)).
	OR	OR	
	PM CEMS	a. Install, certify, operate, and maintain the PM CEMS	Performance Specification 11 at Appendix B to part 60 of this chapter and Procedure 2 at Appendix F to Part 60 of this chapter.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §§63.10010 (a), (b), (c), and (d).

		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see §63.10007(e)).
2. Total or individual non-Hg HAP metals	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration	Method 29 at Appendix A-8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at Appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see §63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the HCl and HF emissions concentrations	Method 26 or Method 26A at Appendix A-8 to part 60 of this chapter or Method 320 at Appendix A to part 63 of this chapter or ASTM 6348-03[3] with (1) additional quality assurance measures in footnote[4] and (2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit. Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate

			and electrical output data (see §63.10007(e)).
	OR	OR	
	HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS	Appendix B of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §§63.10010 (a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see §63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at Appendix A-8 to part 60 of this chapter, ASTM D6784[3], or Method 29 at Appendix A-8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see §63.10007(e)).
	OR	OR	
		Hg CEMS a. Install, certify, operate, and maintain the CEMS	Sections 3.2.1 and 5.1 of Appendix A of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §§63.10010 (a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of Appendix A to this subpart.
	OR	OR	
	Sorbent trap monitoring system	a. Install, certify, operate, and maintain the sorbent trap monitoring system	Sections 3.2.2 and 5.2 of Appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §§63.10010 (a), (b), (c), and (d).
			Section 6 of Appendix A to this subpart.

		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	
	OR	OR	
	LEE testing	a. Select sampling ports location and the number of traverse points	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at Appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G, or 2H at Appendix A-1 or A-2 to part 60 of this chapter or flow monitoring system certified per Appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981,[3] or diluent gas monitoring systems certified according to Part 75 of this chapter.
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at Appendix A-8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (*i.e.,* per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per Appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see §63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 22.0 lb/year threshold	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.
5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, certify, operate, and maintain the CEMS	Part 75 of this chapter and §§63.10010 (a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and §§63.10010 (a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see §63.10007(e)).

[1]Regarding emissions data collected during periods of startup or shutdown, see §§63.10020(b) and (c) and §63.10021(h).

[2]See Tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.

[3]Incorporated by reference, see §63.14.

[4]When using ASTM D6348-03, the following conditions must be met: (1) The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory; (2) For ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%)R must be determined for each target analyte (see Equation A5.5); (3) For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be 70% ≤ R ≤ 130%; and (4) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

$$Reported\ Result = \frac{(Measured\ Concentration\ in\ Stack)}{\%R} \times 100$$

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[77 FR 9464, Feb. 16, 2012, as amended at 78 FR 24091, Apr. 24, 2013]

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Table 6 to Subpart UUUUU of Part 63—Establishing PM CPMS Operating Limits

As stated in §63.10007, you must comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
1. Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an existing EGU	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to §63.10010(h)(1)	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal)	Data from the PM CPMS and the PM or HAP metals performance tests	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the three run performance test. 3. Determine the highest 1-hour average PM CPMS measured during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.
2. Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for a new EGU	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to §63.10010(h)(1)	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal)	Data from the PM CPMS and the PM or HAP metals performance tests	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of §63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

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Table 7 to Subpart UUUUU of Part 63—Demonstrating Continuous Compliance

As stated in §63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following:

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO_2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average of all of the quality assured hourly average PM CPMS output data (e.g., milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired EGUs to measure compliance with one or more non-PM (or its alternative emission limits) applicable emissions limit in Table 1 or 2, or PM (or its alternative emission limits) applicable emissions limit in Table 2	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in §63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown	Operating in accordance with Table 3.

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Table 8 to Subpart UUUUU of Part 63—Reporting Requirements

As stated in §63.10031, you must comply with the following requirements for reports:

You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in §63.10031(c)(1) through (4); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods	Semiannually according to the requirements in §63.10031(b).

	during which the CMSs were out-of-control during the reporting period; and	
	c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in §63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in §63.8(c)(7), the report must contain the information in §63.10031(e)	

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Table 9 to Subpart UUUUU of Part 63—Applicability of General Provisions to Subpart UUUUU

As stated in §63.10040, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Applies to subpart UUUUU
§63.1	Applicability	Yes.
§63.2	Definitions	Yes. Additional terms defined in §63.10042.
§63.3	Units and Abbreviations	Yes.
§63.4	Prohibited Activities and Circumvention	Yes.
§63.5	Preconstruction Review and Notification Requirements	Yes.
§63.6(a), (b)(1)-(b)(5), (b)(7), (c), (f)(2)-(3), (g), (h)(2)-(h)(9), (i), (j)	Compliance with Standards and Maintenance Requirements	Yes.
§63.6(e)(1)(i)	General Duty to minimize emissions	No. See §63.10000(b) for general duty requirement.
§63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§63.6(e)(3)	SSM Plan requirements	No.
§63.6(f)(1)	SSM exemption	No.
§63.6(h)(1)	SSM exemption	No.
§63.7(a), (b), (c), (d), (e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§63.7(e)(1)	Performance testing	No. See §63.10007.
§63.8	Monitoring Requirements	Yes.
63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See §63.10000(b) for general duty requirement.
§63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§63.9	Notification requirements	Yes, except for the 60-day notification prior to conducting a performance test in §63.9(d); instead use a 30-day notification period per §63.10030(d).
§63.10(a), (b)(1), (c), (d)(1)-(2), (e), and (f)	Recordkeeping and Reporting Requirements	Yes, except for the requirements to submit written reports under §63.10 (e)(3)(v).
§63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns	No.
§63.10(b)(2)(ii)		

	Recordkeeping of malfunctions	No. See 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§63.10(b)(2)(iii)	Maintenance records	Yes.
§63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM	No.
§63.10(b)(2)(v)	Actions taken to minimize emissions during SSM	No.
§63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§63.10(b)(2)(vii)-(ix)	Other CMS requirements	Yes.
§63.10(b)(3),and (d)(3)-(5)		No.
§63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions	Yes.
§63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions	Yes.
§63.10(c)(10)	Recording nature and cause of malfunctions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§63.10(c)(11)	Recording corrective actions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§63.10(c)(15)	Use of SSM Plan	No.
§63.10(d)(5)	SSM reports	No. See 63.10021(h) and (i) for malfunction reporting requirements.
§63.11	Control Device Requirements	No.
§63.12	State Authority and Delegation	Yes.
§63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§63.1(a)(5), (a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9)	Reserved	No.

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Appendix A to Subpart UUUUU of Part 63—Hg Monitoring Provisions

1. General Provisions

1.1 *Applicability.* These monitoring provisions apply to the measurement of total vapor phase mercury (Hg) in emissions from electric utility steam generating units, using either a mercury continuous emission monitoring system (Hg CEMS) or a sorbent trap monitoring system. The Hg CEMS or sorbent trap monitoring system must be capable of measuring the total vapor phase mercury in units of the applicable emissions standard (e.g., lb/TBtu or lb/GWh), regardless of speciation.

1.2 *Initial Certification and Recertification Procedures.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall comply with the initial certification and recertification procedures in section 4 of this appendix.

1.3 *Quality Assurance and Quality Control Requirements.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall meet the applicable quality assurance requirements in section 5 of this appendix.

1.4 *Missing Data Procedures.* The owner or operator of an affected unit is not required to substitute for missing data from Hg CEMS or sorbent trap monitoring systems. Any process operating hour for which quality-assured Hg concentration data are not obtained is counted as an hour of monitoring system downtime.

2. MONITORING OF HG EMISSIONS

2.1 *Monitoring System Installation Requirements.* Flue gases from the affected units under this subpart vent to the atmosphere through a variety of exhaust configurations including single stacks, common stack configurations, and multiple stack configurations. For each of these configurations, §63.10010(a) specifies the appropriate location(s) at which to install continuous monitoring systems (CMS). These CMS installation provisions apply to the Hg CEMS, sorbent trap monitoring systems, and other continuous monitoring systems that provide data for the Hg emissions calculations in section 6.2 of this appendix.

2.2 *Primary and Backup Monitoring Systems.* In the electronic monitoring plan described in section 7.1.1.2.1 of this appendix, you must designate a primary Hg CEMS or sorbent trap monitoring system. The primary system must be used to report hourly Hg concentration values when the system is able to provide quality-assured data, *i.e.,* when the system is "in control". However, to increase data availability in the event of a primary monitoring system outage, you may install, operate, maintain, and calibrate backup monitoring systems, as follows:

2.2.1 *Redundant Backup Systems.* A redundant backup monitoring system may be either a separate Hg CEMS with its own probe, sample interface, and analyzer, or a separate sorbent trap monitoring system. A redundant backup system is one that is permanently installed at the unit or stack location, and is kept on "hot standby" in case the primary monitoring system is unable to provide quality-assured data. A redundant backup system must be represented as a unique monitoring system in the electronic monitoring plan. Each redundant backup monitoring system must be certified according to the applicable provisions in section 4 of this appendix and must meet the applicable on-going QA requirements in section 5 of this appendix.

2.2.2 *Non-redundant Backup Monitoring Systems.* A non-redundant backup monitoring system is a separate Hg CEMS or sorbent trap system that has been certified at a particular unit or stack location, but is not permanently installed at that location. Rather, the system is kept on "cold standby" and may be reinstalled in the event of a primary monitoring system outage. A non-redundant backup monitoring system must be represented as a unique monitoring system in the electronic monitoring plan. Non-redundant backup Hg CEMS must complete the same certification tests as the primary monitoring system, with one exception. The 7-day calibration error test is not required for a non-redundant backup Hg CEMS. Except as otherwise provided in section 2.2.4.5 of this appendix, a non-redundant backup monitoring system may only be used for 720 hours per year at a particular unit or stack location.

2.2.3 *Temporary Like-kind Replacement Analyzers.* When a primary Hg analyzer needs repair or maintenance, you may temporarily install a like-kind replacement analyzer, to minimize data loss. Except as otherwise provided in section 2.2.4.5 of this appendix, a temporary like-kind replacement analyzer may only be used for 720 hours per year at a particular unit or stack location. The analyzer must be represented as a component of the primary Hg CEMS, and must be assigned a 3-character component ID number, beginning with the prefix "LK".

2.2.4 *Quality Assurance Requirements for Non-redundant Backup Monitoring Systems and Temporary Like-kind Replacement Analyzers.* To quality-assure the data from non-redundant backup Hg monitoring systems and temporary like-kind replacement Hg analyzers, the following provisions apply:

2.2.4.1 When a certified non-redundant backup sorbent trap monitoring system is brought into service, you must follow the procedures for routine day-to-day operation of the system, in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

2.2.4.2 When a certified non-redundant backup Hg CEMS or a temporary like-kind replacement Hg analyzer is brought into service, a calibration error test and a linearity check must be performed and passed. A single point system integrity check is also required, unless a NIST-traceable source of oxidized Hg was used for the calibration error test.

2.2.4.3 Each non-redundant backup Hg CEMS or temporary like-kind replacement Hg analyzer shall comply with all required daily, weekly, and quarterly quality-assurance test requirements in section 5 of this appendix, for as long as the system or analyzer remains in service.

2.2.4.4 For the routine, on-going quality-assurance of a non-redundant backup Hg monitoring system, a relative accuracy test audit (RATA) must be performed and passed at least once every 8 calendar quarters at the unit or stack location(s) where the system will be used.

2.2.4.5 To use a non-redundant backup Hg monitoring system or a temporary like-kind replacement analyzer for more than 720 hours per year at a particular unit or stack location, a RATA must first be performed and passed at that location.

3. MERCURY EMISSIONS MEASUREMENT METHODS

The following definitions, equipment specifications, procedures, and performance criteria are applicable to the measurement of vapor-phase Hg emissions from electric utility steam generating units, under relatively low-dust conditions (*i.e.*, sampling in the stack or duct after all pollution control devices). The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents the sum of elemental Hg ($Hg^{0,}$ CAS Number 7439-97-6) and oxidized forms of Hg.

3.1 *Definitions.*

3.1.1 *Mercury Continuous Emission Monitoring System or Hg CEMS* means all of the equipment used to continuously determine the total vapor phase Hg concentration. The measurement system may include the following major subsystems: sample acquisition, Hg^{+2} to Hg^{0} converter, sample transport, sample conditioning, flow control/gas manifold, gas analyzer, and data acquisition and handling system (DAHS). Hg CEMS may be nominally real-time or time-integrated, batch sampling systems that sample the gas on an intermittent basis and concentrate on a collection medium before intermittent analysis and reporting.

3.1.2 *Sorbent Trap Monitoring System* means the equipment required to monitor Hg emissions continuously by using paired sorbent traps containing iodated charcoal (IC) or other suitable sorbent medium. The monitoring system consists of a probe, paired sorbent traps, an umbilical line, moisture removal components, an airtight sample pump, a gas flow meter, and an automated data acquisition and handling system. The system samples the stack gas at a constant proportional rate relative to the stack gas volumetric flow rate. The sampling is a batch process. The average Hg concentration in the stack gas for the sampling period is determined, in units of micrograms per dry standard cubic meter (µg/dscm), based on the sample volume measured by the gas flow meter and the mass of Hg collected in the sorbent traps.

3.1.3 *NIST* means the National Institute of Standards and Technology, located in Gaithersburg, Maryland.

3.1.4 *NIST-Traceable Elemental Hg Standards* means either: compressed gas cylinders having known concentrations of elemental Hg, which have been prepared according to the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards"; or calibration gases having known concentrations of elemental Hg, produced by a generator that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators" or an interim version of that protocol.

3.1.5 *NIST-Traceable Source of Oxidized Hg* means a generator that is capable of providing known concentrations of vapor phase mercuric chloride ($HgCl_2$), and that meets the performance requirements of the "EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators" or an interim version of that protocol.

3.1.6 *Calibration Gas* means a NIST-traceable gas standard containing a known concentration of elemental or oxidized Hg that is produced and certified in accordance with an EPA traceability protocol.

3.1.7 *Span Value* means a conservatively high estimate of the Hg concentrations to be measured by a CEMS. The span value of a Hg CEMS should be set to approximately twice the concentration corresponding to the emission standard, rounded off as appropriate (see section 3.2.1.4.2 of this appendix).

3.1.8 *Zero-Level Gas* means calibration gas containing a Hg concentration that is below the level detectable by the Hg gas analyzer in use.

3.1.9 *Low-Level Gas* means calibration gas with a concentration that is 20 to 30 percent of the span value.

3.1.10 *Mid-Level Gas* means calibration gas with a concentration that is 50 to 60 percent of the span value.

3.1.11 *High-Level Gas* means calibration gas with a concentration that is 80 to 100 percent of the span value.

3.1.12 *Calibration Error Test* means a test designed to assess the ability of a Hg CEMS to measure the concentrations of calibration gases accurately. A zero-level gas and an upscale gas are required for this test. For the upscale gas, either a mid-level gas or a high-level gas may be used, and the gas may either be an elemental or oxidized Hg standard.

3.1.13 *Linearity Check* means a test designed to determine whether the response of a Hg analyzer is linear across its measurement range. Three elemental Hg calibration gas standards (*i.e.*, low, mid, and high-level gases) are required for this test.

3.1.14 *System Integrity Check* means a test designed to assess the transport and measurement of oxidized Hg by a Hg CEMS. Oxidized Hg standards are used for this test. For a three-level system integrity check, low, mid, and high-level calibration gases are required. For a single-level check, either a mid-level gas or a high-level gas may be used.

3.1.15 *Cycle Time Test* means a test designed to measure the amount of time it takes for a Hg CEMS, while operating normally, to respond to a known step change in gas concentration. For this test, a zero gas and a high-level gas are required. The high-level gas may be either an elemental or an oxidized Hg standard.

3.1.16 *Relative Accuracy Test Audit* or *RATA* means a series of nine or more test runs, directly comparing readings from a Hg CEMS or sorbent trap monitoring system to measurements made with a reference stack test method. The relative accuracy (RA) of the monitoring system is expressed as the absolute mean difference between the monitoring system and reference method measurements plus the absolute value of the 2.5 percent error confidence coefficient, divided by the mean value of the reference method measurements.

3.1.17 *Unit Operating Hour* means a clock hour in which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.1.18 *Stack Operating Hour* means a clock hour in which gases flow through a particular monitored stack or duct (either for part of the hour or for the entire hour), while the associated unit(s) are combusting fuel.

3.1.19 *Operating Day* means a calendar day in which a source combusts any fuel.

3.1.20 Quality Assurance *(QA) Operating Quarter* means a calendar quarter in which there are at least 168 unit or stack operating hours (as defined in this section).

3.1.21 *Grace Period* means a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

3.2 *Continuous Monitoring Methods.*

3.2.1 *Hg CEMS.* A typical Hg CEMS is shown in Figure A-1. The CEMS in Figure A-1 is a dilution extractive system, which measures Hg concentration on a wet basis, and is the most commonly-used type of Hg CEMS. Other system designs may be used, provided that the CEMS meets the performance specifications in section 4.1.1 of this appendix.

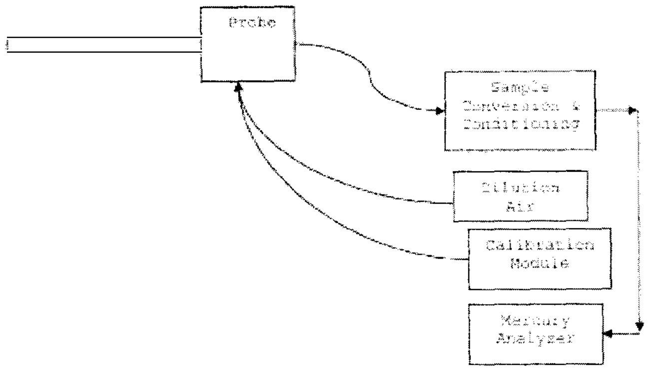

FIGURE A-1. TYPICAL MERCURY CEMS

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3.2.1.1 *Equipment Specifications.*

3.2.1.1.1 *Materials of Construction.* All wetted sampling system components, including probe components prior to the point at which the calibration gas is introduced, must be chemically inert to all Hg species. Materials such as perfluoroalkoxy (PFA) Teflon™, quartz, and treated stainless steel (SS) are examples of such materials.

3.2.1.1.2 *Temperature Considerations.* All system components prior to the Hg^{+2} to Hg^{0} converter must be maintained at a sample temperature above the acid gas dew point.

3.2.1.1.3 *Measurement System Components.*

3.2.1.1.3.1 *Sample Probe.* The probe must be made of the appropriate materials as noted in paragraph 3.2.1.1.1 of this section, heated when necessary, as described in paragraph 3.2.1.1.3.4 of this section, and configured with ports for introduction of calibration gases.

3.2.1.1.3.2 *Filter or Other Particulate Removal Device.* The filter or other particulate removal device is part of the measurement system, must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section, and must be included in all system tests.

3.2.1.1.3.3 *Sample Line.* The sample line that connects the probe to the converter, conditioning system, and analyzer must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section.

3.2.1.1.3.4 *Conditioning Equipment.* For wet basis systems, such as the one shown in Figure A-1, the sample must be kept above its dew point either by: heating the sample line and all sample transport components up to the inlet of the analyzer (and, for hot-wet extractive systems, also heating the analyzer); or diluting the sample prior to analysis using a dilution probe system. The components required for these operations are considered to be conditioning equipment. For dry basis measurements, a condenser, dryer or other suitable device is required to remove moisture continuously from the sample gas, and any equipment needed to heat the probe or sample line to avoid condensation prior to the moisture removal component is also required.

3.2.1.1.3.5 *Sampling Pump.* A pump is needed to push or pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. If a mechanical sample pump is used and its surfaces are in contact with the sample gas prior to detection, the pump must be leak free and must be constructed of a material that is non-reactive to the gas being sampled (see paragraph 3.2.1.1.1 of this section). For dilution-type measurement systems, such as the system shown in Figure A-1, an ejector pump (eductor) may be used to create a sufficient vacuum that sample gas will be drawn through a critical orifice at a constant rate. The ejector pump must be constructed of any material that is non-reactive to the gas being sampled.

3.2.1.1.3.6 *Calibration Gas System(s).* Design and equip each Hg CEMS to permit the introduction of known concentrations of elemental Hg and $HgCl_2$ separately, at a point preceding the sample extraction filtration system, such that the entire measurement system can be checked. The calibration gas system(s) must be designed so that the flow rate exceeds the sampling system flow requirements and that the gas is delivered to the CEMS at atmospheric pressure.

3.2.1.1.3.7 *Sample Gas Delivery.* The sample line may feed directly to either a converter, a by-pass valve (for Hg speciating systems), or a sample manifold. All valve and/or manifold components must be made of material that is non-reactive to the gas sampled and the calibration gas, and must be configured to safely discharge any excess gas.

3.2.1.1.3.8 *Hg Analyzer.* An instrument is required that continuously measures the total vapor phase Hg concentration in the gas stream. The analyzer may also be capable of measuring elemental and oxidized Hg separately.

3.2.1.1.3.9 *Data Recorder.* A recorder, such as a computerized data acquisition and handling system (DAHS), digital recorder, or data logger, is required for recording measurement data.

3.2.1.2 *Reagents and Standards.*

3.2.1.2.1 *NIST Traceability.* Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this section) shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg^0 and $HgCl_2$ are required. Special reagents and equipment may be needed to prepare the Hg^0 and $HgCl_2$ gas standards (e.g., NIST-traceable solutions of $HgCl_2$ and gas generators equipped with mass flow controllers).

3.2.1.2.2 *Required Calibration Gas Concentrations.*

3.2.1.2.2.1 *Zero-Level Gas.* A zero-level calibration gas with a Hg concentration below the level detectable by the Hg analyzer is required for calibration error tests and cycle time tests of the CEMS.

3.2.1.2.2.2 *Low-Level Gas.* A low-level calibration gas with a Hg concentration of 20 to 30 percent of the span value is required for linearity checks and 3-level system integrity checks of the CEMS. Elemental Hg standards are required for the linearity checks and oxidized Hg standards are required for the system integrity checks.

3.2.1.2.2.3 *Mid-Level Gas.* A mid-level calibration gas with a Hg concentration of 50 to 60 percent of the span value is required for linearity checks and for 3-level system integrity checks of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error tests.

3.2.1.2.2.4 *High-Level Gas.* A high-level calibration gas with a Hg concentration of 80 to 100 percent of the span value is required for linearity checks, 3-level system integrity checks, and cycle time tests of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error and cycle time tests.

3.2.1.3 *Installation and Measurement Location.* For the Hg CEMS and any additional monitoring system(s) needed to convert Hg concentrations to the desired units of measure (*i.e.*, a flow monitor, CO_2 or O_2 monitor, and/or moisture monitor, as applicable), install each monitoring system at a location: that is consistent with 63.10010(a); that represents the emissions exiting to the atmosphere; and where it is likely that the CEMS can pass the relative accuracy test.

3.2.1.4 *Monitor Span and Range Requirements.* Determine the appropriate span and range value(s) for the Hg CEMS as described in paragraphs 3.2.1.4.1 through 3.2.1.4.3 of this section.

3.2.1.4.1 *Maximum Potential Concentration.* There are three options for determining the maximum potential Hg concentration (MPC). Option 1 applies to coal combustion. You may use a default value of 10 μg/scm for all coal ranks (including coal refuse) except for lignite; for lignite, use 16 μg/scm. If different coals are blended as part of normal operation, use the highest MPC for any fuel in the blend. Option 2 is to base the MPC on the results of site-specific Hg emission testing. This option may be used only if the unit does not have add-on Hg emission controls or a flue gas desulfurization system, or if testing is performed upstream of all emission control devices. If Option 2 is selected, perform at least three test runs at the normal operating load, and the highest Hg concentration obtained in any of the tests shall be the MPC. Option 3 is to use fuel sampling and analysis to estimate the MPC. To make this estimate, use the average Hg content (*i.e.,* the weight percentage) from at least three representative fuel samples, together with other available information, including, but not limited to the maximum fuel feed rate, the heating value of the fuel, and an appropriate F-factor. Assume that all of the Hg in the fuel is emitted to the atmosphere as vapor-phase Hg.

3.2.1.4.2 *Span Value.* To determine the span value of the Hg CEMS, multiply the Hg concentration corresponding to the applicable emissions standard by two. If the result of this calculation is an exact multiple of 10 µg/scm, use the result as the span value. Otherwise, round off the result to either: the next highest integer; the next highest multiple of 5 µg/scm; or the next highest multiple of 10 µg/scm.

3.2.1.4.3 *Analyzer Range.* The Hg analyzer must be capable of reading Hg concentration as high as the MPC.

3.2.2 *Sorbent Trap Monitoring System.* A sorbent trap monitoring system (as defined in paragraph 3.1.2 of this section) may be used as an alternative to a Hg CEMS. If this option is selected, the monitoring system shall be installed, maintained, and operated in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. The system shall be certified in accordance with the provisions of section 4.1.2 of this appendix.

3.2.3 *Other Necessary Data Collection.* To convert measured hourly Hg concentrations to the units of the applicable emissions standard (*i.e.,* lb/TBtu or lb/GWh), additional data must be collected, as described in paragraphs 3.2.3.1 through 3.2.3.3 of this section. Any additional monitoring systems needed for this purpose must be certified, operated, maintained, and quality-assured according to the applicable provisions of part 75 of this chapter (see §§63.10010(b) through (d)). The calculation methods for the types of emission limits described in paragraphs 3.2.3.1 and 3.2.3.2 of this section are presented in section 6.2 of this appendix.

3.2.3.1 *Heat Input-Based Emission Limits.* For a heat input-based Hg emission limit (*i.e.,* in lb/TBtu), data from a certified CO_2 or O_2 monitor are needed, along with a fuel-specific F-factor and a conversion constant to convert measured Hg concentration values to the units of the standard. In some cases, the stack gas moisture content must also be considered in making these conversions.

3.2.3.2 *Electrical Output-Based Emission Rates.* If the applicable Hg limit is electrical output-based (*i.e.,* lb/GWh), hourly electrical load data and unit operating times are required in addition to hourly data from a certified stack gas flow rate monitor and (if applicable) moisture data.

3.2.3.3 *Sorbent Trap Monitoring System Operation.* Routine operation of a sorbent trap monitoring system requires the use of a certified stack gas flow rate monitor, to maintain an established ratio of stack gas flow rate to sample flow rate.

4. Certification and Recertification Requirements

4.1 *Certification Requirements.* All Hg CEMS and sorbent trap monitoring systems and the additional monitoring systems used to continuously measure Hg emissions in units of the applicable emissions standard in accordance with this appendix must be certified in a timely manner, such that the initial compliance demonstration is completed no later than the applicable date in §63.9984(f).

4.1.1 *Hg CEMS.* Table A-1, below, summarizes the certification test requirements and performance specifications for a Hg CEMS. The CEMS may not be used to report quality-assured data until these performance criteria are met. Paragraphs 4.1.1.1 through 4.1.1.5 of this section provide specific instructions for the required tests. All tests must be performed with the affected unit(s) operating (*i.e.,* combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the certification tests.

4.1.1.1 *7-Day Calibration Error Test.* Perform the 7-day calibration error test on 7 consecutive source operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in sections 3.1.8, 3.1.10, and 3.1.11 of this appendix). Either elemental or oxidized NIST-traceable Hg standards (as defined in sections 3.1.4 and 3.1.5 of this appendix) may be used for the test. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate the Hg CEMS in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over nonconsecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the monitor (*i.e.*, resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined, and use only the unadjusted analyzer responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A-1. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A-1.

4.1.1.2 *Linearity Check.* Perform the linearity check using low, mid, and high-level concentrations of NIST-traceable elemental Hg standards. Three gas injections at each concentration level are required, with no two successive injections at the same concentration level. Introduce the calibration gas at the gas injection port, as specified in section 3.2.1.1.3.6 of this appendix. Operate the CEMS at its normal operating temperature and conditions. Pass the calibration gas through all filters, scrubbers, conditioners, and other components used during normal sampling, and through as much of the sampling probe as is practical. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Record the monitor response from the data acquisition and handling system for each gas injection. At each concentration level, use the average analyzer response to calculate the linearity error (LE), as described in Table A-1. The LE must either meet the main performance specification or the alternative specification in Table A-1.

4.1.1.3 *Three-Level System Integrity Check.* Perform the 3-level system integrity check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as described in Table A-1. The SIE must either meet the main performance specification or the alternative specification in Table A-1. (NOTE: This test is not required if the CEMS does not have a converter).

TABLE A-1—REQUIRED CERTIFICATION TESTS AND PERFORMANCE SPECIFICATIONS FOR HG CEMS

For this required certification test . . .	The main performance specification[1] is . . .	The alternate performance specification[1] is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test[2]	$\lvert R - A\rvert \leq 5.0\%$ of span value, for both the zero and upscale gases, on each of the 7 days	$\lvert R - A\rvert \leq 1.0$ µg/scm	The alternate specification may be used on any day of the test.
Linearity check[3]	$\lvert R - A_{avg}\rvert \leq 10.0\%$ of the reference gas concentration at each calibration gas level (low, mid, or high)	$\lvert R - A_{avg}\rvert \leq 0.8$ µg/scm	The alternate specification may be used at any gas level.
3-level system integrity check[4]	$\lvert R - A_{avg}\rvert \leq 10.0\%$ of the reference gas concentration at each calibration gas level	$\lvert R - A_{avg}\rvert \leq 0.8$ µg/scm	The alternate specification may be used at any gas level.
RATA	20.0% RA	$\lvert RM_{avg} - C_{avg}\rvert \leq 1.0$ µg/scm**	$RM_{avg} < 5.0$ µg/scm.
Cycle time test[2]	15 minutes.[5]		

[1]Note that $\lvert R - A\rvert$ is the absolute value of the difference between the reference gas value and the analyzer reading. $\lvert R - A_{avg,}\rvert$ is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.

[2]Use either elemental or oxidized Hg standards; a mid-level or high-level upscale gas may be used. This test is not required for Hg CEMS that use integrated batch sampling; however, those monitors must be capable of recording at least one Hg concentration reading every 15 minutes.

[3]Use elemental Hg standards.

[4]Use oxidized Hg standards. Not required if the CEMS does not have a converter.

[5]Stability criteria—Readings change by <2.0% of span *or* by ≤0.5 µg/scm, for 2 minutes.

** Note that $|RM_{avg}-C_{avg}|$ is the absolute difference between the mean reference method value and the mean CEMS value from the RATA. The arithmetic difference between RM_{avg} and C_{avg} can be either + or −.

4.1.1.4 *Cycle Time Test*. Perform the cycle time test, using a zero-level gas and a high-level calibration gas.

Either an elemental or oxidized NIST-traceable Hg standard may be used as the high-level gas. Perform the test in two stages—upscale and downscale. The slower of the upscale and downscale response times is the cycle time for the CEMS. Begin each stage of the test by injecting calibration gas after achieving a stable reading of the stack emissions. The cycle time is the amount of time it takes for the analyzer to register a reading that is 95 percent of the way between the stable stack emissions reading and the final, stable reading of the calibration gas concentration. Use the following criterion to determine when a stable reading of stack emissions or calibration gas has been attained—the reading is stable if it changes by no more than 2.0 percent of the span value or 0.5 µg/scm (whichever is less restrictive) for two minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Integrated batch sampling type Hg CEMS are exempted from this test; however, these systems must be capable of delivering a measured Hg concentration reading at least once every 15 minutes. If necessary to increase measurement sensitivity of a batch sampling type Hg CEMS for a specific application, you may petition the Administrator for approval of a time longer than 15 minutes between readings.

4.1.1.5 *Relative Accuracy Test Audit (RATA)*. Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784-02 (Reapproved 2008), "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)" (incorporated by reference, see §63.14) and Methods 29, 30A, and 30B in appendix A-8 to part 60. When Method 29 or ASTM D6784-02 is used, paired sampling trains are required. To validate a Method 29 or ASTM D6784-02 test run, calculate the relative deviation (RD) using Equation A-1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the average concentration is ≤ 1.0 µg/dscm, the RD must not exceed 20 percent. The RD results are also acceptable if the absolute difference between the two Hg concentrations does not exceed 0.2 µg/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

$$RD = \frac{|C_a - C_b|}{C_a + C_b} x 100 \quad \text{(Eq. A-1)}$$

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Where:

RD = Relative deviation between the Hg concentrations of samples "a" and "b" (percent)

C_a = Hg concentration of Hg sample "a" (µg/dscm)

C_b = Hg concentration of Hg sample "b" (µg/dscm)

4.1.1.5.1 *Special Considerations.* A minimum of nine valid test runs must be performed, directly comparing the CEMS measurements to the reference method. More than nine test runs may be performed. If this option is chosen, the results from a maximum of three test runs may be rejected so long as the total number of test results used to determine the relative accuracy is greater than or equal to nine; however, all data must be reported including the rejected data. The minimum time per run is 21 minutes if Method 30A is used. If Method 29, Method 30B, or ASTM D6784-02 (Reapproved 2008), "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)" (incorporated by reference, see §63.14) is used, the time per run must be long enough to collect a sufficient mass of Hg to analyze. Complete the RATA within 168 unit operating hours, except when Method 29 or ASTM D6784-02 is used, in which case up to 336 operating hours may be taken to finish the test.

4.1.1.5.2 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in Appendix B to part 60 of this chapter (see Equations 2-3 through 2-6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry. The CEMS must either meet the main performance specification or the alternative specification in Table A-1.

4.1.1.5.3 *Bias Adjustment.* Measurement or adjustment of Hg CEMS data for bias is not required.

4.1.2 *Sorbent Trap Monitoring Systems.* For the initial certification of a sorbent trap monitoring system, only a RATA is required.

4.1.2.1 *Reference Methods.* The acceptable reference methods for the RATA of a sorbent trap monitoring system are the same as those listed in paragraph 4.1.1.5 of this section.

4.1.2.2 "The special considerations specified in paragraph 4.1.1.5.1 of this section apply to the RATA of a sorbent trap monitoring system. During the RATA, the monitoring system must be operated and quality-assured in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter with the following exceptions for sorbent trap section 2 breakthrough:

4.1.2.2.1 For stack Hg concentrations >1 µg/dscm, ≤10% of section 1 Hg mass;

4.1.2.2.2 For stack Hg concentrations ≤1 µg/dscm and >0.5 µg/dscm, ≤ 20% of section 1 Hg mass;

4.1.2.2.3 For stack Hg concentrations ≤0.5 µg/dscm and >0.1 µg/dscm, ≤ 50% of section 1 Hg mass; and

4.1.2.2.4 For stack Hg concentrations ≤0.1µg/dscm, no breakthrough criterion assuming all other QA/QC specifications are met.

4.1.2.3 The type of sorbent material used by the traps during the RATA must be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

4.1.2.4 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the sorbent trap monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2-3 through 2-6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry.The main and alternative RATA performance specifications in Table A-1 for Hg CEMS also apply to the sorbent trap monitoring system.

4.1.2.5 *Bias Adjustment.* Measurement or adjustment of sorbent trap monitoring system data for bias is not required.

4.1.3 *Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems.* Monitoring systems that are used to measure stack gas volumetric flow rate, diluent gas concentration, or stack gas moisture content, either for routine operation of a sorbent trap monitoring system or to convert Hg concentration data to units of the applicable emission limit, must be certified in accordance with the applicable provisions of part 75 of this chapter.

4.2 *Recertification.* Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS or sorbent trap monitoring system that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. Ongoing Quality Assurance (QA) and Data Validation

5.1 *Hg CEMS.*

5.1.1 *Required QA Tests.* Periodic QA testing of each Hg CEMS is required following initial certification. The required QA tests, the test frequencies, and the performance specifications that must be met are summarized in Table A-2, below. All tests must be performed with the affected unit(s) operating (*i.e.,* combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the tests. For each test, follow the same basic procedures in section 4.1.1 of this appendix that were used for initial certification.

5.1.2 *Test Frequency.* The frequency for the required QA tests of the Hg CEMS shall be as follows:

5.1.2.1 Calibration error tests of the Hg CEMS are required daily, except during unit outages. Use either NIST-traceable elemental Hg standards or NIST-traceable oxidized Hg standards for these calibrations. Both a zero-level gas and either a mid-level or high-level gas are required for these calibrations.

5.1.2.2 Perform a linearity check of the Hg CEMS in each QA operating quarter, using low-level, mid-level, and high-level NIST-traceable elemental Hg standards. For units that operate infrequently, limited exemptions from this test are allowed for "non-QA operating quarters". A maximum of three consecutive exemptions for this reason are permitted, following the quarter of the last test. After the third consecutive exemption, a linearity check must be performed in the next calendar quarter or within a grace period of 168 unit or stack operating hours after the end of that quarter. The test frequency for 3-level system integrity checks (if performed in lieu of linearity checks) is the same as for the linearity checks. Use low-level, mid-level, and high-level NIST-traceable oxidized Hg standards for the system integrity checks.

5.1.2.3 If required, perform a single-level system integrity check weekly, *i.e.,* once every 7 operating days (see the third column in Table A-2).

5.1.2.4 The test frequency for the RATAs of the Hg CEMS shall be annual, *i.e.,* once every four QA operating quarters. For units that operate infrequently, extensions of RATA deadlines are allowed for non-QA operating quarters. Following a RATA, if there is a subsequent non-QA quarter, it extends the deadline for the next test by one calendar quarter. However, there is a limit to these extensions; the deadline may not be extended beyond the end of the eighth calendar quarter after the quarter of the last test. At that point, a RATA must either be performed within the eighth calendar quarter or in a 720 hour unit or stack operating hour grace period following that quarter. When a required annual RATA is done within a grace period, the deadline for the next RATA is three QA operating quarters after the quarter in which the grace period test is performed.

5.1.3 *Grace Periods.*

5.1.3.1 A 168 unit or stack operating hour grace period is available for quarterly linearity checks and 3-level system integrity checks of the Hg CEMS.

5.1.3.2 A 720 unit or stack operating hour grace period is available for RATAs of the Hg CEMS.

5.1.3.3 There is no grace period for weekly system integrity checks. The test must be completed once every 7 operating days.

5.1.4 *Data Validation.* The Hg CEMS is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any one of the acceptance criteria for the required QA tests in Table A-2 is not met. The CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.1.5 *Conditional Data Validation.* For certification, recertification, and diagnostic testing of Hg monitoring systems, and for the required QA tests when non-redundant backup Hg monitoring systems or temporary like-kind Hg analyzers are brought into service, the conditional data validation provisions in §§75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete 7-day calibration error tests, linearity checks, cycle time tests, and RATAs shall be as specified in §75.20(b)(3)(iv) of this chapter. Required system integrity checks must be completed within 168 unit or stack operating hours after the probationary calibration error test.

TABLE A-2—ON-GOING QA TEST REQUIREMENTS FOR HG CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Calibration error test	Daily	• Use either a mid- or high-level gas	$\|R-A\| \leq 5.0\%$ of span value. *or* $\|R-A\| \leq 1.0$ μg/scm.
		• Use either elemental or oxidized Hg	
		• Calibrations are not required when the unit is not in operation	
Single-level system integrity check	Weekly[1]	• Required only for systems with converters	$\|R-A_{avg}\| \leq 10.0\%$ of the reference gas value. *or* $\|R-A_{avg}\| \leq 0.8$ μg/scm.
		• Use oxidized Hg—either mid- or high-level	
		• Not required if daily calibrations are done with a NIST-traceable source of oxidized Hg	
Linearity check *or* 3-level system integrity check	Quarterly[3]	• Required in each "QA operating quarter"[2]—and no less than once every 4 calendar quarters	$\|R-A_{avg}\| \leq 10.0\%$ of the reference gas value, at each calibration gas level. *or* $\|R-A_{avg}\| \leq 0.8$ μg/scm.
		• 168 operating hour grace period available	
		• Use elemental Hg for linearity check	
		• Use oxidized Hg for system integrity check	
		• For system integrity check, CEMS must have a converter	
RATA	Annual[4]	• Test deadline may be extended for "non-QA operating quarters", up to a maximum of 8 quarters from the quarter of the previous test	20.0% RA. *or* $\|RM_{avg}-C_{avg}\| \leq 1.0$ μg/scm, *if* $RM_{avg} < 5.0$ μg/scm.
		• 720 operating hour grace period available	

[1]"Weekly" means once every 7 operating days.

[2]A "QA operating quarter" is a calendar quarter with at least 168 unit or stack operating hours.

[3]"Quarterly" means once every QA operating quarter.

[4]"Annual" means once every four QA operating quarters.

5.1.6 *Adjustment of Span.* If you discover that a span adjustment is needed (e.g., if the Hg concentration readings exceed the span value for a significant percentage of the unit operating hours in a calendar quarter), you must implement the span adjustment within 90 days after the end of the calendar quarter in which you identify the need for the adjustment. A diagnostic linearity check is required within 168 unit or stack operating hours after changing the span value.

5.2 *Sorbent Trap Monitoring Systems.*

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter. The

QA/QC criteria for routine operation of the system are summarized in Table 12B-1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.2.2 For ongoing QA, periodic RATAs of the system are required.

5.2.2.1 The RATA frequency shall be annual, *i.e.*, once every four QA operating quarters. The provisions in section 5.1.2.4 of this appendix pertaining to RATA deadline extensions also apply to sorbent trap monitoring systems.

5.2.2.2 The same RATA performance criteria specified in Table A-2 for Hg CEMS also apply to the annual RATAs of the sorbent trap monitoring system.

5.2.2.3 A 720 unit or stack operating hour grace period is available for RATAs of the monitoring system.

5.2.3 Data validation for sorbent trap monitoring systems shall be done in accordance with Table 12B-1 in Performance Specification (PS) 12B in appendix B to part 60 of this chapter. All periods of invalid data shall be counted as hours of monitoring system downtime.

5.3 *Flow Rate, Diluent Gas, and Moisture Monitoring Systems.* The on-going QA test requirements for these monitoring systems are specified in part 75 of this chapter (see §§63.10010(b) through (d)).

5.4 *QA/QC Program Requirements.* The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the Hg CEMS and/or sorbent trap monitoring systems that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the diluent gas, flow rate, and moisture monitoring systems described in section 3.2.1.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

5.4.1 *General Requirements.*

5.4.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the Hg CEMS and/or sorbent trap monitoring system(s) in proper operating condition and a schedule for those procedures. Include, at a minimum, all procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

5.4.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

5.4.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any Hg CEMS or sorbent trap monitoring system in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded (e.g., changing the dilution ratio of a CEMS), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

5.4.2 *Specific Requirements for Hg CEMS.*

5.4.2.1 *Daily Calibrations, Linearity Checks and System Integrity Checks.* Keep a written record of the procedures used for daily calibrations of the Hg CEMS. If moisture and/or chlorine is added to the Hg calibration gas, document how the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration is accounted for in an appropriate manner. Also keep records of the procedures used to perform linearity checks of the Hg CEMS and the procedures for system integrity checks of the Hg CEMS. Document how the test results are calculated and evaluated.

5.4.2.2 *Monitoring System Adjustments.* Document how each component of the Hg CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

5.4.2.3 *Relative Accuracy Test Audits.* Keep a written record of procedures used for RATAs of the Hg CEMS. Indicate the reference methods used and document how the test results are calculated and evaluated.

5.4.3 *Specific Requirements for Sorbent Trap Monitoring Systems.*

5.4.3.1 *Sorbent Trap Identification and Tracking.* Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for chain of custody purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg collection period.

5.4.3.2 *Monitoring System Integrity and Data Quality.* Document the procedures used to perform the leak checks when a sorbent trap is placed in service and removed from service. Also Document the other QA procedures used to ensure system integrity and data quality, including, but not limited to, gas flow meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in Table 12B-1 in section 9.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. All reference meters used to calibrate the gas flow meters (e.g., wet test meters) shall be periodically recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST-traceable calibration device is used as a reference flow meter, the QA plan must include a protocol for ongoing maintenance and periodic recalibration to maintain the accuracy and NIST-traceability of the calibrator.

5.4.3.3 *Hg Analysis.* Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps. Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 11.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter.

5.4.3.4 *Data Collection Period.* State, and provide the rationale for, the minimum acceptable data collection period (e.g., one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Address such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.4.3.5 *Relative Accuracy Test Audit Procedures.* Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

6. DATA REDUCTION AND CALCULATIONS

6.1 Data Reduction.

6.1.1 Reduce the data from Hg CEMS to hourly averages, in accordance with §60.13(h)(2) of this chapter.

6.1.2 For sorbent trap monitoring systems, determine the Hg concentration for each data collection period and assign this concentration value to each operating hour in the data collection period.

6.1.3 For any operating hour in which valid data are not obtained, either for Hg concentration or for a parameter used in the emissions calculations (*i.e.,* flow rate, diluent gas concentration, or moisture, as applicable), do not calculate the Hg emission rate for that hour. For the purposes of this appendix, part 75 substitute data values are not considered to be valid data.

6.1.4 Operating hours in which valid data are not obtained for Hg concentration are considered to be hours of monitor downtime. The use of substitute data for Hg concentration is not required.

6.2 *Calculation of Hg Emission Rates.* Use the applicable calculation methods in paragraphs 6.2.1 and 6.2.2 of this section to convert Hg concentration values to the appropriate units of the emission standard.

6.2.1 *Heat Input-Based Hg Emission Rates.* Calculate hourly heat input-based Hg emission rates, in units of lb/TBtu, according to sections 6.2.1.1 through 6.2.1.4 of this appendix.

6.2.1.1 Select an appropriate emission rate equation from among Equations 19-1 through 19-9 in EPA Method 19 in appendix A-7 to part 60 of this chapter.

6.2.1.2 Calculate the Hg emission rate in lb/MMBtu, using the equation selected from Method 19. Multiply the Hg concentration value by 6.24×10^{-11} to convert it from µg/scm to lb/scf. In cases where an appropriate F-factor is not listed in Table 19-2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Also, for startup and shutdown hours, you may calculate the Hg emission rate using the applicable diluent cap value specified in section 3.3.4.1 of appendix F to part 75 of this chapter, provided that the diluent gas monitor is not out-of-control and the hourly average O_2 concentration is above 14.0% O_2 (19.0% for an IGCC) or the hourly average CO_2 concentration is below 5.0% CO_2 (1.0% for an IGCC), as applicable.

6.2.1.3 Multiply the lb/MMBtu value obtained in section 6.2.1.2 of this appendix by 10^6 to convert it to lb/TBtu.

6.2.1.4 The heat input-based Hg emission rate limit in Table 2 to this subpart must be met on a 30 boiler operating day rolling average basis, except as otherwise provided in §63.10009(a)(2). Use Equation 19-19 in EPA Method 19 to calculate the Hg emission rate for each averaging period. The term E_{hj} in Equation 19-19 must be in the units of the applicable emission limit. Do not include non-operating hours with zero emissions in the average.

6.2.2 *Electrical Output-Based Hg Emission Rates.* Calculate electrical output-based Hg emission limits in units of lb/GWh, according to sections 6.2.2.1 through 6.2.2.3 of this appendix.

6.2.2.1 Calculate the Hg mass emissions for each operating hour in which valid data are obtained for all parameters, using Equation A-2 of this section (for wet-basis measurements of Hg concentration) or Equation A-3 of this section (for dry-basis measurements), as applicable:

$$M_h = K C_h Q_h \qquad \text{(Equation A-2)}$$

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Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/µg-scf,

C_h = Hourly average Hg concentration, wet basis (µg/scm)

Q_h = Stack gas volumetric flow rate for the hour (scfh).

(NOTE: Use unadjusted flow rate values; bias adjustment is not required)

$$M_h = K C_h Q_h (1 - B_{ws}) \qquad \text{(Equation A-3)}$$

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Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/µg-scf.

C_h = Hourly average Hg concentration, dry basis (µg/dscm).

Q_h = Stack gas volumetric flow rate for the hour (scfh)

(NOTE: Use unadjusted flow rate values; bias adjustment is not required).

B_{ws} = Moisture fraction of the stack gas, expressed as a decimal (equal to % H_2O/100)

6.2.2.2 Use Equation A-4 of this section to calculate the emission rate for each unit or stack operating hour in which valid data are obtained for all parameters.

$$E_{ho} = \frac{M_h}{(MW)_h} x\, 10^3 \qquad \text{(Equation A-4)}$$

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Where:

E_{ho} = Electrical output-based Hg emission rate (lb/GWh).

M_h = Hg mass emission rate for the hour, from Equation A-2 or A-3 of this section, as applicable (lb/h).

$(MW)_h$ = Gross electrical load for the hour, in megawatts (MW).

10^3 = Conversion factor from megawatts to gigawatts.

6.2.2.3 The applicable electrical output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30-boiler operating day rolling average basis, except as otherwise provided in §63.10009(a)(2). Use Equation A-5 of this section to calculate the Hg emission rate for each averaging period.

$$\bar{E}_o = \frac{\sum_{h=1}^{n} E_{cho}}{n} \qquad \text{(Equation A-5)}$$

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Where:

$\bar{E}_o$ = Hg emission rate for the averaging period (lb/GWh).

E_{cho} = Electrical output-based hourly Hg emission rate for unit or stack operating hour "h" in the averaging period, from Equation A-4 of this section (lb/GWh).

n = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters.

(*Note:* Do *not* include non-operating hours with zero emission rates in the average).

7. RECORDKEEPING AND REPORTING

7.1 *Recordkeeping Provisions.* For the Hg CEMS and/or sorbent trap monitoring systems and any other necessary monitoring systems installed at each affected unit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with §63.10033. The file shall contain the information in paragraphs 7.1.1 through 7.1.10 of this section.

7.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the Hg CEMS and/or sorbent trap monitoring system(s) and any other monitoring system(s) (*i.e.,* flow rate, diluent gas, or moisture systems) needed for routine operation of a sorbent trap monitoring system or to convert Hg concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall Document how the data derived from these systems ensure that all Hg emissions from the unit or stack are monitored and reported.

7.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

7.1.1.2 *Contents of the Monitoring Plan.* For Hg CEMS and sorbent trap monitoring systems, the monitoring plan shall contain the information in sections 7.1.1.2.1 and 7.1.1.2.2 of this appendix, as applicable. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the information required for those systems under §75.53 (g) of this chapter.

7.1.1.2.1 *Electronic.* The electronic monitoring plan records must include the following: unit or stack ID number(s); monitoring location(s); the Hg monitoring methodologies used; Hg monitoring system information, including, but not limited to: Unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate Hg emissions; Hg monitor span and range information The electronic monitoring plan shall be evaluated and submitted using the Emissions Collection and Monitoring Plan

System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of the EPA.

7.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the Hg monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations; miscellaneous technical justifications.

7.1.2 *Operating Parameter Records.* The owner or operator shall record the following information for each operating hour of each affected unit and also for each group of units utilizing a common stack, to the extent that these data are needed to convert Hg concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 7.1.2.1 and 7.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 7.1.2.1, 7.1.2.2, and (if applicable) 7.1.2.4 of this section.

7.1.2.1 The date and hour;

7.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

7.1.2.3 The hourly gross unit load (rounded to nearest MWe); and

7.1.2.4 If applicable, the F-factor used to calculate the heat input-based Hg emission rate.

7.1.3 *Hg Emissions Records (Hg CEMS).* For each affected unit or common stack using a Hg CEMS, the owner or operator shall record the following information for each unit or stack operating hour:

7.1.3.1 The date and hour;

7.1.3.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the CEMS provides a quality-assured value of Hg concentration for the hour;

7.1.3.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (μg/scm, rounded to three significant figures);

7.1.3.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour. This code may be entered manually when a temporary like-kind replacement Hg analyzer is used for reporting; and

7.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to §75.32 of this chapter.

7.1.4 *Hg Emissions Records (Sorbent Trap Monitoring Systems).* For each affected unit or common stack using a sorbent trap monitoring system, each owner or operator shall record the following information for the unit or stack operating hour in each data collection period:

7.1.4.1 The date and hour;

7.1.4.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the sorbent trap system provides a quality-assured value of Hg concentration for the hour;

7.1.4.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (μg/scm, rounded to three significant figures). Note that when a quality-assured Hg concentration value is obtained for a particular data collection period, that single concentration value is applied to each operating hour of the data collection period.

7.1.4.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour;

7.1.4.5 The average flow rate of stack gas through each sorbent trap (in appropriate units, e.g., liters/min, cc/min, dscm/min);

7.1.4.6 The gas flow meter reading (in dscm, rounded to the nearest hundredth), at the beginning and end of the collection period and at least once in each unit operating hour during the collection period;

7.1.4.7 The ratio of the stack gas flow rate to the sample flow rate, as described in section 12.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter; and

7.1.4.8 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to §75.32 of this chapter.

7.1.5 *Stack Gas Volumetric Flow Rate Records.*

7.1.5.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required for routine operation of sorbent trap monitoring systems, to maintain the required ratio of stack gas flow rate to sample flow rate (see section 8.2.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter). Hourly stack gas flow rate data are also needed in order to demonstrate compliance with electrical output-based Hg emissions limits, as provided in section 6.2.2 of this appendix.

7.1.5.2 For each affected unit or common stack, if hourly measurements of stack gas flow rate are needed for sorbent trap monitoring system operation or to convert Hg concentrations to the units of the emission standard, use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in §75.57(c)(2) of this chapter.

7.1.6 *Records of Stack Gas Moisture Content.*

7.1.6.1 Correction of hourly Hg concentration data for moisture is sometimes required when converting Hg concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

7.1.6.1.1 For sorbent trap monitoring systems;

7.1.6.1.2 For Hg CEMS that measure Hg concentration on a dry basis, when you must calculate electrical output-based Hg emission rates; and

7.1.6.1.3 When using certain equations from EPA Method 19 in appendix A-7 to part 60 of this chapter to calculate heat input-based Hg emission rates.

7.1.6.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage from §75.11(b)(1) of this chapter or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in §75.57(c)(3) of this chapter.

7.1.7 *Records of Diluent Gas (CO_2* or O_2) Concentration.

7.1.7.1 When a heat input-based Hg mass emissions limit must be met, in units of lb/TBtu, hourly measurements of CO_2 or O_2 concentration are required to convert Hg concentrations to units of the standard.

7.1.7.2 If hourly measurements of diluent gas concentration are needed, use a certified CO_2 or O_2 monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly CO_2 or O_2 concentration records, as specified in §75.57(g) of this chapter.

7.1.8 *Hg Emission Rate Records.* For applicable Hg emission limits in units of lb/TBtu or lb/GWh, record the following information for each affected unit or common stack:

7.1.8.1 The date and hour;

7.1.8.2 The hourly Hg emissions rate (lb/TBtu or lb/GWh, as applicable, calculated according to section 6.2.1 or 6.2.2 of this appendix, rounded to three significant figures), if valid values of Hg concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

7.1.8.3 An identification code for the formula (either the selected equation from Method 19 in section 6.2.1 of this appendix or Equation A-4 in section 6.2.2 of this appendix) used to derive the hourly Hg emission rate from Hg concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

7.1.8.4 A code indicating that the Hg emission rate was not calculated for the hour, if valid data for Hg concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

7.1.9 *Certification and Quality Assurance Test Records.* For any Hg CEMS and sorbent trap monitoring systems used to provide data under this subpart, record the following certification and quality-assurance information:

7.1.9.1 The reference values, monitor responses, and calculated calibration error (CE) values, and a flag to indicate whether the test was done using elemental or oxidized Hg, for all required 7-day calibration error tests and daily calibration error tests of the Hg CEMS;

7.1.9.2 The reference values, monitor responses, and calculated linearity error (LE) or system integrity error (SIE) values for all linearity checks of the Hg CEMS, and for all single-level and 3-level system integrity checks of the Hg CEMS;

7.1.9.3 The CEMS and reference method readings for each test run and the calculated relative accuracy results for all RATAs of the Hg CEMS and/or sorbent trap monitoring systems;

7.1.9.4 The stable stack gas and calibration gas readings and the calculated results for the upscale and downscale stages of all required cycle time tests of the Hg CEMS or, for a batch sampling Hg CEMS, the interval between measured Hg concentration readings;

7.1.9.5 Supporting information for all required RATAs of the Hg monitoring systems, including records of the test dates, the raw reference method and monitoring system data, the results of sample analyses to substantiate the reported test results, and records of sampling equipment calibrations;

7.1.9.6 For sorbent trap monitoring systems, also keep records of the results of all analyses of the sorbent traps used for routine daily operation of the system, and information documenting the results of all leak checks and the other applicable quality control procedures described in Table 12B-1 of Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

7.1.9.7 For stack gas flow rate, diluent gas, and (if applicable) moisture monitoring systems, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in §75.59 of this chapter.

7.2 *Reporting Requirements.*

7.2.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting Hg emissions from each affected unit (or group of units monitored at a common stack) under this subpart:

7.2.1.1 Notifications, in accordance with paragraph 7.2.2 of this section;

7.2.1.2 Monitoring plan reporting, in accordance with paragraph 7.2.3 of this section;

7.2.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 7.2.4 of this section; and

7.2.1.4 Electronic quarterly report submittals, in accordance with paragraph 7.2.5 of this section.

7.2.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) under this subpart in accordance with §63.10030.

7.2.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) under this subpart using Hg CEMS or sorbent trap monitoring system to measure Hg emissions, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

7.2.3.1 Submit the electronic and hard copy information in section 7.1.1.2 of this appendix pertaining to the Hg monitoring systems at least 21 days prior to the applicable date in §63.9984. Also submit the monitoring plan information in §75.53.(g) pertaining to the flow rate, diluent gas, and moisture monitoring systems within that same time frame, if the required records are not already in place.

7.2.3.2 Whenever an update of the monitoring plan is required, as provided in paragraph 7.1.1.1 of this section. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

7.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 7.1 of this appendix.

7.2.4 *Certification, Recertification, and Quality-Assurance Test Reporting.* Except for daily QA tests of the required monitoring systems (*i.e.*, calibration error tests and flow monitor interference checks), the results of all required certification, recertification, and quality-assurance tests described in paragraphs 7.1.9.1 through 7.1.9.7 of this section (except for test results previously submitted, e.g., under the ARP) shall be submitted electronically, using the ECMPS Client Tool, either prior to or concurrent with the relevant quarterly electronic emissions report.

7.2.5 *Quarterly Reports.*

7.2.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in §63.9984, the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack) under this subpart.

7.2.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

7.2.5.3 Each electronic quarterly report shall include the following information:

7.2.5.3.1 The date of report generation;

7.2.5.3.2 Facility identification information;

7.2.5.3.3 The information in paragraphs 7.1.2 through 7.1.8 of this section, as applicable to the Hg emission measurement methodology (or methodologies) used and the units of the Hg emission standard(s); and

7.2.5.3.4 The results of all daily calibration error tests of the Hg CEMS, as described in paragraph 7.1.9.1 of this section and (if applicable) the results of all daily flow monitor interference checks.

7.2.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all Hg emissions from the affected unit(s) under this subpart have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

[77 FR 9464, Feb. 16, 2012, as amended at 77 FR 23408, Apr. 19, 2012; 78 FR 24093, Apr. 24, 2013]

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Appendix B to Subpart UUUUU of Part 63—-HCl and HF Monitoring Provisions

1. APPLICABILITY

These monitoring provisions apply to the measurement of HCl and/or HF emissions from electric utility steam generating units, using CEMS. The CEMS must be capable of measuring HCl and/or HF in the appropriate units of the applicable emissions standard (e.g., lb/MMBtu, lb/MWh, or lb/GWh).

2. MONITORING OF HCL AND/OR HF EMISSIONS

2.1 *Monitoring System Installation Requirements.* Install HCl and/or HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit in accordance with Performance Specification 15 for extractive Fourier Transform Infrared Spectroscopy (FTIR) continuous emissions monitoring systems in appendix B to part 60 of this chapter and §63.10010(a).

2.2 *Primary and Backup Monitoring Systems.* The provisions pertaining to primary and redundant backup monitoring systems in section 2.2 of appendix A to this subpart apply to HCl and HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit.

2.3 *FTIR Monitoring System Equipment, Supplies, Definitions, and General Operation.* The provisions of Performance Specification 15 Sections 2.0, 3.0, 4.0, 5.0, 6.0, and 10.0 apply.

3. Initial Certification Procedures

The initial certification procedures for the HCl or HF CEMS used to provide data under this subpart are as follows:

3.1 The HCl and/or HF CEMS must be certified according to Performance Specification 15 using the procedures for gas auditing and comparison to a reference method (RM) as specified in sections 3.1.1 and 3.1.2 below. (PLEASE NOTE: EPA plans to publish a technology neutral performance specification and appropriate on-going quality-assurance requirements for HCl CEMS in the near future along with amendments to this appendix to accommodate their use.)

3.1.1 You must conduct a gas audit of the HCl and/or HF CEMS as described in section 9.1 of Performance Specification 15, with the exceptions listed in sections 3.1.2.1 and 3.1.2.2 below.

3.1.1.1 The audit sample gas does not have to be obtained from the Administrator; however, it must be (1) from a secondary source of certified gases (*i.e.*, independent of any calibration gas used for the daily calibration assessments) and (2) directly traceable to National Institute of Standards and Technology (NIST) or VSL Dutch Metrology Institute (VSL) reference materials through an unbroken chain of comparisons. If audit gas traceable to NIST or VSL reference materials is not available, you may use a gas with a concentration certified to a specified uncertainty by the gas manufacturer.

3.1.1.2 Analyze the results of the gas audit using the calculations in section 12.1 of Performance Specification 15. The calculated correction factor (CF) from Eq. 6 of Performance Specification 15 must be between 0.85 and 1.15. You do not have to test the bias for statistical significance.

3.1.2 You must perform a relative accuracy test audit or RATA according to section 11.1.1.4 of Performance Specification 15 and the requirements below. Perform the RATA of the HCl or HF CEMS at normal load. Acceptable HCl/HF reference methods (RM) are Methods 26 and 26A in appendix A-8 to part 60 of this chapter, Method 320 in Appendix A to this part, or ASTM D6348-03 (Reapproved 2010) "Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy" (incorporated by reference, see §63.14), each applied based on the criteria set forth in Table 5 of this subpart.

3.1.2.1 When ASTM D6348-03 is used as the RM, the following conditions must be met:

3.1.2.1.1 The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory;

3.1.2.1.2 In ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);

3.1.2.1.3 For the ASTM D6348-03 test data to be acceptable for a target analyte, %R must be 70% ≤ R ≤ 130%; and

3.1.2.1.4 The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

$$\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%\text{R}} x\, 100 \qquad (\text{Eq. B-1})$$

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3.1.2.2 The relative accuracy (RA) of the HCl or HF CEMS must be no greater than 20 percent of the mean value of the RM test data in units of ppm on the same moisture basis. Alternatively, if the mean RM value is less than 1.0 ppm, the RA results are acceptable if the absolute value of the difference between the mean RM and CEMS values does not exceed 0.20 ppm.

3.2 Any additional stack gas flow rate, diluent gas, and moisture monitoring system(s) needed to express pollutant concentrations in units of the applicable emissions limit must be certified according to part 75 of this chapter.

4. RECERTIFICATION PROCEDURES

Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: Replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. ON-GOING QUALITY ASSURANCE REQUIREMENTS

5.1 For on-going QA test requirements for HCl and HF CEMS, implement the quality assurance/quality control procedures of Performance Specification 15 of appendix B to part 60 of this chapter as set forth in sections 5.1.1 through 5.1.3 and 5.3.2 of this appendix.

5.1.1 On a daily basis, you must assess the calibration error of the HCl or HF CEMS using either a calibration transfer standard as specified in Performance Specification 15 Section 10.1 which references Section 4.5 of the FTIR Protocol or a HCl and/or HF calibration gas at a concentration no greater than two times the level corresponding to the applicable emission limit. A calibration transfer standard is a substitute calibration compound chosen to ensure that the FTIR is performing well at the wavelength regions used for analysis of the target analytes. The measured concentration of the calibration transfer standard or HCl and/or HF calibration gas results must agree within ± 5 percent of the reference gas value after correction for differences in pressure.

5.1.2 On a quarterly basis, you must conduct a gas audit of the HCl and/or HF CEMS as described in section 3.1.1 of this appendix. For the purposes of this appendix, "quarterly" means once every "QA operating quarter" (as defined in section 3.1.20 of appendix A to this subpart). You have the option to use HCl gas in lieu of HF gas for conducting this audit on an HF CEMS. To the extent practicable, perform consecutive quarterly gas audits at least 30 days apart. The initial quarterly audit is due in the first QA operating quarter following the calendar quarter in which certification testing of the CEMS is successfully completed. Up to three consecutive exemptions from the quarterly audit requirement are allowed for "non-QA operating quarters" (*i.e.,* calendar quarters in which there are less than 168 unit or stack operating hours). However, no more than four consecutive calendar quarters may elapse without performing a gas audit, except as otherwise provided in section 5.3.3.2.1 of this appendix.

5.1.3 You must perform an annual relative accuracy test audit or RATA of the HCl or HF CEMS as described in section 3.1.2 of this appendix. Perform the RATA at normal load. For the purposes of this appendix, "annual" means once every four "QA operating quarters" (as defined in section 3.1.20 of appendix A to this subpart). The first annual RATA is due within four QA operating quarters following the calendar quarter in which the initial certification testing of the HCl or HF CEMS is successfully completed. The provisions in section 5.1.2.4 of appendix A to this subpart pertaining to RATA deadline extensions also apply.

5.2 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable on-going QA test requirements of part 75 of this chapter.

5.3 *Data Validation.*

5.3.1 *Out-of-Control Periods.* A HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.3.2 *Grace Periods*. For the purposes of this appendix, a "grace period" is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.3.2.1 For the flow rate, diluent gas, and moisture monitoring systems described in section 5.2 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.3.2.2 For the purposes of this appendix, if the deadline for a required gas audit or RATA of a HCl or HF CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.3.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit; or

5.3.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.3.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.3.2.3.1 For a gas audit or RATA of the monitoring systems described in section 5.1 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.3.2.3.2 For the gas audit of a HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit is required for that quarter.

5.3.2.3.3 For the RATA of a HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.3.3 *Conditional Data Validation*> For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, and for the required QA tests when non-redundant backup monitoring systems or temporary like-kind replacement analyzers are brought into service, the conditional data validation provisions in §§75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in §75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a gas audit shall be the same as for a linearity check (*i.e.,* 168 unit or stack operating hours).

6. Missing Data Requirements

For the purposes of this appendix, the owner or operator of an affected unit shall not substitute for missing data from HCl or HF CEMS. Any process operating hour for which quality-assured HCl or HF concentration data are not obtained is counted as an hour of monitoring system downtime.

7. Bias Adjustment

Bias adjustment of hourly emissions data from a HCl or HF CEMS is not required.

8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the HCl and/or HF CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in section 5.2 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

8.1 *General Requirements for HCl and HF CEMS.*

8.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the HCl and/or HF CEMS in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

8.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

8.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any HCl or HF CEMS in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: Date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded and a written explanation of the procedures used to make the adjustment(s) shall be kept.

8.2 *Specific Requirements for HCl and HF CEMS.* The following requirements are specific to HCl and HF CEMS:

8.2.1 Keep a written record of the procedures used for each type of QA test required for each HCl and HF CEMS. Explain how the results of each type of QA test are calculated and evaluated.

8.2.2 Explain how each component of the HCl and/or HF CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

9. Data Reduction and Calculations

9.1 Design and operate the HCl and/or HF CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

9.2 Reduce the HCl and/or HF concentration data to hourly averages in accordance with §60.13 (h)(2) of this chapter.

9.3 Convert each hourly average HCl or HF concentration to an HCl or HF emission rate expressed in units of the applicable emissions limit.

9.3.1 For heat input-based emission rates, select an appropriate emission rate equation from among Equations 19-1 through 19-9 in EPA Method 19 in appendix A-7 to part 60 of this chapter, to calculate the HCl or HF emission rate in lb/MMBtu. Multiply the HCl concentration value (ppm) by 9.43×10^{-8} to convert it to lb/scf, for use in the applicable Method 19 equation. For HF, the conversion constant from ppm to lb/scf is 5.18×10^{-8}.

9.3.2 For electrical output-based emission rates, first calculate the HCl or HF mass emission rate (lb/h), using an equation that has the general form of Equation A-2 or A-3 in appendix A to this subpart (as applicable), replacing the value of K with 9.43×10^{-8} lb/scf-ppm (for HCl) or 5.18×10^{-8} (for HF) and defining C_h as the hourly average HCl or HF concentration in ppm. Then, use Equation A-4 in appendix A to this subpart to calculate the HCl or HF emission rate in lb/GWh. If the applicable HCl or HF limit is expressed in lb/MWh, divide the result from Equation A-4 by 10^3.

9.4 Use Equation A-5 in appendix A of this subpart to calculate the required 30 operating day rolling average HCl or HF emission rates. Round off each 30 operating day average to two significant figures. The term E_{ho} in Equation A-5 must be in the units of the applicable emissions limit.

10. Recordkeeping Requirements

10.1 For each HCl or HF CEMS installed at an affected source, and for any other monitoring system(s) needed to convert pollutant concentrations to units of the applicable emissions limit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with §63.10033. The file shall contain the information in paragraphs 10.1.1 through 10.1.8 of this section.

10.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the HCl and/or HF

CEMS and any other monitoring system(s) (*i.e,* flow rate, diluent gas, or moisture systems) needed to convert pollutant concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall explain how the data derived from these systems ensure that all HCl or HF emissions from the unit or stack are monitored and reported.

10.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous HCl or HF monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

10.1.1.2 *Contents of the Monitoring Plan.* For HCl and/or HF CEMS, the monitoring plan shall contain the applicable electronic and hard copy information in sections 10.1.1.2.1 and 10.1.1.2.2 of this appendix. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the electronic and hard copy information required for those systems under §75.53 (g) of this chapter. The electronic monitoring plan shall be evaluated using the ECMPS Client Tool.

10.1.1.2.1 *Electronic.* Record the unit or stack ID number(s); monitoring location(s); the HCl or HF monitoring methodology used (*i.e.,* CEMS); HCl or HF monitoring system information, including, but not limited to: unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; monitor span and range information (if applicable).

10.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations (if applicable); miscellaneous technical justifications.

10.1.2 *Operating Parameter Records.* For the purposes of this appendix, the owner or operator shall record the following information for each operating hour of each affected unit or group of units utilizing a common stack, to the extent that these data are needed to convert pollutant concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 10.1.2.1 and 10.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 10.1.2.1, 10.1.2.2, and (if applicable) 10.1.2.4 of this section.

10.1.2.1 The date and hour;

10.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

10.1.2.3 The hourly gross unit load (rounded to nearest MWge); and

10.1.2.4 If applicable, the F-factor used to calculate the heat input-based pollutant emission rate.

10.1.3 *HCl and/or HF Emissions Records.* For HCl and/or HF CEMS, the owner or operator must record the following information for each unit or stack operating hour:

10.1.3.1 The date and hour;

10.1.3.2 Monitoring system and component identification codes, as provided in the electronic monitoring plan, for each hour in which the CEMS provides a quality-assured value of HCl or HF concentration (as applicable);

10.1.3.3 The pollutant concentration, for each hour in which a quality-assured value is obtained. For HCl and HF, record the data in parts per million (ppm), rounded to three significant figures.

10.1.3.4 A special code, indicating whether or not a quality-assured HCl or HF concentration value is obtained for the hour. This code may be entered manually when a temporary like-kind replacement HCl or HF analyzer is used for reporting; and

10.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to §75.32 of this chapter.

10.1.4 *Stack Gas Volumetric Flow Rate Records.*

10.1.4.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required to demonstrate compliance with electrical output-based HCl or HF emissions limits (*i.e.*, lb/MWh or lb/GWh).

10.1.4.2 Use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in §75.57(c)(2) of this chapter.

10.1.5 *Records of Stack Gas Moisture Content.*

10.1.5.1 Correction of hourly pollutant concentration data for moisture is sometimes required when converting concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

10.1.5.1.1 To calculate electrical output-based pollutant emission rates, when using a CEMS that measures pollutant concentrations on a dry basis; and

10.1.5.1.2 To calculate heat input-based pollutant emission rates, when using certain equations from EPA Method 19 in appendix A-7 to part 60 of this chapter.

10.1.5.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage for coal-fired units from §75.11(b)(1) of this chapter, an Administrator approved default moisture value for non-coal-fired units (as per paragraph 63.10010(d) of this subpart), or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you elect to use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in §75.57(c)(3) of this chapter.

10.1.6 *Records of Diluent Gas (CO_2 or O_2) Concentration.*

10.1.6.1 To assess compliance with a heat input-based HCl or HF emission rate limit in units of lb/MMBtu, hourly measurements of CO_2 or O_2 concentration are required to convert pollutant concentrations to units of the standard.

10.1.6.2 If hourly measurements of diluent gas concentration are needed, you must use a certified CO_2 or O_2 monitor that meets the requirements of part 75 of this chapter to record the required data. For all diluent gas monitors, you must keep hourly CO_2 or O_2 concentration records, as specified in §75.57(g) of this chapter.

10.1.7 *HCl and HF Emission Rate Records.* For applicable HCl and HF emission limits in units of lb/MMBtu, lb/MWh, or lb/GWh, record the following information for each affected unit or common stack:

10.1.7.1 The date and hour;

10.1.7.2 The hourly HCl and/or HF emissions rate (lb/MMBtu, lb/MWh, or lb/GWh, as applicable, rounded to three significant figures), for each hour in which valid values of HCl or HF concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

10.1.7.3 An identification code for the formula used to derive the hourly HCl or HF emission rate from HCl or HF concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

10.1.7.4 A code indicating that the HCl or HF emission rate was not calculated for the hour, if valid data for HCl or HF concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

10.1.8 *Certification and Quality Assurance Test Records.* For the HCl and/or HF CEMS used to provide data under this subpart at each affected unit (or group of units monitored at a common stack), record the following information for all required certification, recertification, diagnostic, and quality-assurance tests:

10.1.8.1 *HCl and HF CEMS.*

10.1.8.1.1 For all required daily calibrations (including calibration transfer standard tests) of the HCl or HF CEMS, record the test dates and times, reference values, monitor responses, and calculated calibration error values;

10.1.8.1.2 For gas audits of HCl or HF CEMS, record the date and time of each spiked and unspiked sample, the audit gas reference values and uncertainties. Keep records of all calculations and data analyses required under sections 9.1 and 12.1 of Performance Specification 15, and the results of those calculations and analyses.

10.1.8.1.3 For each RATA of a HCl or HF CEMS, record the date and time of each test run, the reference method(s) used, and the reference method and HCl or HF CEMS values. Keep records of the data analyses and calculations used to determine the relative accuracy.

10.1.8.2 *Additional Monitoring Systems.* For the stack gas flow rate, diluent gas, and moisture monitoring systems described in section 3.2 of this appendix, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in §75.59(a) of this chapter.

11. Reporting Requirements

11.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting HCl and/or HF emissions from each affected unit (or group of units monitored at a common stack):

11.1.1 Notifications, in accordance with paragraph 11.2 of this section;

11.1.2 Monitoring plan reporting, in accordance with paragraph 11.3 of this section;

11.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 11.4 of this section; and

11.1.4 Electronic quarterly report submittals, in accordance with paragraph 11.5 of this section.

11.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) in accordance with §63.10030.

11.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) using HCl and/or HF CEMS, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

11.3.1 Submit the electronic and hard copy information in section 10.1.1.2 of this appendix pertaining to the HCl and/or HF monitoring systems at least 21 days prior to the applicable date in §63.9984. Also, if applicable, submit monitoring plan information pertaining to any required flow rate, diluent gas, and/or moisture monitoring systems within that same time frame, if the required records are not already in place.

11.3.2 Update the monitoring plan when required, as provided in paragraph 10.1.1.1 of this appendix. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

11.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 10.1 of this appendix.

11.4 *Certification, Recertification, and Quality-Assurance Test Reporting Requirements.* Except for daily QA tests (*i.e.,* calibrations and flow monitor interference checks), which are included in each electronic quarterly emissions report, use the ECMPS Client Tool to submit the results of all required certification, recertification, quality-assurance, and diagnostic tests of the monitoring systems required under this appendix electronically, either prior to or concurrent with the relevant quarterly electronic emissions report.

11.4.1 For daily calibrations (including calibration transfer standard tests), report the information in §75.59(a)(1) of this chapter, excluding paragraphs (a)(1)(ix) through (a)(1)(xi).

11.4.2 For each quarterly gas audit of a HCl or HF CEMS, report:

11.4.2.1 Facility ID information;

11.4.2.2 Monitoring system ID number;

11.4.2.3 Type of test (e.g., quarterly gas audit);

11.4.2.4 Reason for test;

11.4.2.5 Certified audit (spike) gas concentration value (ppm);

11.4.2.6 Measured value of audit (spike) gas, including date and time of injection;

11.4.2.7 Calculated dilution ratio for audit (spike) gas;

11.4.2.8 Date and time of each spiked flue gas sample;

11.4.2.9 Date and time of each unspiked flue gas sample;

11.4.2.10 The measured values for each spiked gas and unspiked flue gas sample (ppm);

11.4.2.11 The mean values of the spiked and unspiked sample concentrations and the expected value of the spiked concentration as specified in section 12.1 of Performance Specification 15 (ppm);

11.4.2.12 Bias at the spike level as calculated using equation 3 in section 12.1 of Performance Specification 15; and

11.4.2.13 The correction factor (CF), calculated using equation 6 in section 12.1 of Performance Specification 15.

11.4.3 For each RATA of a HCl or HF CEMS, report:

11.4.3.1 Facility ID information;

11.4.3.2 Monitoring system ID number;

11.4.3.3 Type of test (*i.e.*, initial or annual RATA);

11.4.3.4 Reason for test;

11.4.3.5 The reference method used;

11.4.3.6 Starting and ending date and time for each test run;

11.4.3.7 Units of measure;

11.4.3.8 The measured reference method and CEMS values for each test run, on a consistent moisture basis, in appropriate units of measure;

11.4.3.9 Flags to indicate which test runs were used in the calculations;

11.4.3.10 Arithmetic mean of the CEMS values, of the reference method values, and of their differences;

11.4.3.11 Standard deviation, as specified in Equation 2-4 of Performance Specification 2 in appendix B to part 60 of this chapter;

11.4.3.12 Confidence coefficient, as specified in Equation 2-5 of Performance Specification 2 in appendix B to part 60 of this chapter; and

11.4.3.13 Relative accuracy calculated using Equation 2-6 of Performance Specification 2 in appendix B to part 60 of this chapter or, if applicable, according to the alternative procedure for low emitters described in section 3.1.2.2 of this appendix. If applicable use a flag to indicate that the alternative RA specification for low emitters has been applied.

11.4.4 *Reporting Requirements for Diluent Gas, Flow Rate, and Moisture Monitoring Systems.* For the certification, recertification, diagnostic, and QA tests of stack gas flow rate, moisture, and diluent gas monitoring systems that are certified and quality-assured according to part 75 of this chapter, report the information in section 10.1.9.3 of this appendix.

11.5 *Quarterly Reports.*

11.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in §63.10005(g), (h), or (j) (whichever is earlier), the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack).

11.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

11.5.3 Each electronic quarterly report shall include the following information:

11.5.3.1 The date of report generation;

11.5.3.2 Facility identification information;

11.5.3.3 The information in sections 10.1.2 through 10.1.7 of this appendix, as applicable to the type(s) of monitoring system(s) used to measure the pollutant concentrations and other necessary parameters.

11.5.3.4 The results of all daily calibrations (including calibration transfer standard tests) of the HCl or HF monitor as described in section 10.1.8.1.1 of this appendix; and

11.5.3.5 If applicable, the results of all daily flow monitor interference checks, in accordance with section 10.1.8.2 of this appendix.

11.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all HCl and/or HF emissions from the affected unit(s) have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

[77 FR 9464, Feb. 16, 2012, as amended at 78 FR 24094, Apr. 24, 2013]

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CERTIFICATE OF SERVICE

I, Cynthia Hook , hereby certify that a copy of this permit has been mailed by first class mail to Entergy Arkansas, Inc. (White Bluff Plant), 1100 White Bluff Road, Redfield, AR, 72132, on this 22nd day of January, 2015.

Cynthia Hook , ASIII, Air Division

STATEMENT OF BASIS

For the issuance of Draft Air Permit # 0263-AOP-R8 AFIN: 35-00110

1. PERMITTING AUTHORITY:

   Arkansas Department of Environmental Quality
   5301 Northshore Drive
   North Little Rock, Arkansas 72118-5317

2. APPLICANT:

   Entergy Arkansas, Inc. (White Bluff Plant)
   1100 White Bluff Road
   Redfield, Arkansas 72132

3. PERMIT WRITER:

   Charles Hurt, P.E.

4. NAICS DESCRIPTION AND CODE:

   NAICS Description: Fossil Fuel Electric Power Generation
   NAICS Code: 221112

5. SUBMITTALS:

   6/28/2013

6. REVIEWER'S NOTES:

   Entergy Arkansas, Inc. - White Bluff located in Redfield, Arkansas is a two-unit electric generating station which generates electric energy for sale. Entergy submitted an application to incorporate the applicable requirements of 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, also referred to as the Mercury Air Toxic Standards (MATS), and to account for the additional traffic on the roads due to deliveries of activated carbon and halide solution deliveries. Two activated carbon silos and two aqueous halide storage units were added to the insignificant activities list. Overall, permitted emission decreased by 77.5 tpy PM and 15.0 tpy PM_{10}.

   The traffic on the roads due to the MATS project was estimated to result in an additional 514 vehicle miles traveled (VMT). Total potential emissions from the additional traffic would be 0.8 tpy and 0.2 tpy PM and PM_{10}, respectively. Specific Condition #89 limits the VMT for the facility. The additional traffic will count towards the existing VMT limits in Specific Condition #89.

In addition to the changes requested in the applications Entergy requested by an email dated November 7, 2013 that vehicle miles travel (VMT) limits in former SC #53 be updated based on the previous application. Review of available information appears to support the claim that the emission limits for SN-06C were calculated using the updated VMT limits and that limits remaining unchanged was an inadvertent oversight when Permit No. 263-AOP-R7 was issued. At the same time Entergy requested revisions to the emission limits for SN-06C due updated AP-42 Section 13.2.1 emissions estimate equation for paved roads. The updated equation predicts lower PM and PM_{10} emissions.

7. COMPLIANCE STATUS:

The following summarizes the current compliance of the facility including active/pending enforcement actions and recent compliance activities and issues.

The facility was last inspected on October 9, 2012. The inspection report did not identify any non-compliance concerns.

8. PSD APPLICABILITY:

a) Did the facility undergo PSD review in this permit (i.e., BACT, Modeling, etc.)? N

b) Is the facility categorized as a major source for PSD? Y

- *Single pollutant ≥ 100 tpy and on the list of 28 or single pollutant ≥ 250 tpy and not on list, or*
- *CO_2e potential to emit ≥ 100,000 tpy and ≥100 tpy/≥250tpy of combined GHGs?*

If yes, explain why this permit modification is not PSD.

In a letter dated February 19, 2013 ADEQ notified Entergy that pursuant to APC&EC Regulation §26.301 (C), no permit or Department pre-authorization is required for the construction associated with the Entergy's proposed pollution control project (MATS). Additionally, Entergy submitted a PSD applicability based on projected actual emissions that indicated less than significant increases.

9. GHG MAJOR SOURCE (TITLE V):

Indicate one:

☒ Facility is classified as a major source for GHG and the permit includes this designation
☐ Facility does not have the physical potential to be a major GHG source
☐ Facility has restrictions on GHG or throughput rates that limit facility to a minor GHG source. Describe these restrictions: ____________________

10. SOURCE AND POLLUTANT SPECIFIC REGULATORY APPLICABILITY:

Source	Pollutant	Regulation (NSPS, NESHAP or PSD)
SN-01 SN-02	PM SO_2 NO_X CO_2 Opacity	40 CFR Part 60, Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971
21	Operating standards only	40 CFR Part 63, Subpart ZZZZ - *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines* 40 CFR Part 60, Subpart IIII - *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*
Facility	Asbestos	40 CFR Part 61, Subpart M – National Emission Standard for Asbestos
SN-01 SN-02	SO_2/NOx	40 CFR Part 72, Subpart A-D – Permits Regulation (Acid Rain)
SN-01 SN-02	HAPS	40 CFR Part 63, Subpart UUUUU – *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units*

11. EMISSION CHANGES AND FEE CALCULATION:

See emission change and fee calculation spreadsheet in Appendix A.

12. AMBIENT AIR EVALUTAIONS:

a) NAAQS:

This permit decision did not involve an emission increase over previously permitted rates; therefore a NAAQS evaluation is not required.

b) Non-Criteria Pollutants:

All of the following modeling results were from modeling performed with the issuance of Air Permit 0263-AOP-R7. No changes were made to the emission rates of any of the Non-Criteria Pollutants. Therefore, no modeling was required.

1st Tier Screening (PAER)

Estimated hourly emissions from the following sources were compared to the Presumptively Acceptable Emission Rate (PAER) for each compound. The Department has deemed the PAER to be the product, in lb/hr, of 0.11 and the Threshold Limit Value (mg/m^3), as listed by the American Conference of Governmental Industrial Hygienists (ACGIH).

Pollutant	TLV (mg/m^3)	PAER (lb/hr) = 0.11 × TLV	Proposed lb/hr	Pass?
Acetaldehyde**	45.0409	4.954499	0.617648	Y
Acrolein*	0.229284	0.025221	0.313487	N
Arsenic	0.01	0.0011	0.443534	N
Benzene	1.597342	0.175708	1.412905	N
Benzyl Chloride	5.176	0.56934	0.756	N
Beryllium	0.00005	5.5E-06	0.023231	N
Cadmium	0.002	0.00022	0.055631	N
Carbon Disulfide	3.11411	0.342552	0.1404	Y
2-Chloroacetophenone	0.316135	0.034775	0.00756	Y
Chloroform	48.82618	5.370879	0.06372	Y
Chromium	0.5	0.055	0.281351	N
Chromium VI	0.01	0.0011	0.08532	N
Cobalt	0.02	0.0022	0.108	N
Cyanide**	5.195951	0.571555	2.7	N
Dimethyl Sulfate	0.515746	0.056732	0.05184	Y
Ethylene Dichloride	40.47444	4.452188	0.0432	Y
Formaldehyde**	0.371779	0.040896	0.768534	N
Hydrogen Chloride**	2.983231	0.328155	1296	N
Hydrogen Fluoride	0.409202	0.045012	162	N
Isophorone**	28.2638	3.109018	0.6264	Y
Manganese	0.2	0.022	0.530301	N
Mercury	0.01	0.0011	0.090191	N
Methyl Chloride	103.2515	11.35767	0.5724	Y
Methyl Hydrazine	0.018843	0.002073	0.1836	N
Nickel	0.1	0.011	0.302951	N
Phenol	19.24335	2.116769	0.01728	Y
POM*	0.2	0.022	0.047377	N
Propionaldehyde	47.52556	5.227812	0.4104	Y
Selenium	0.2	0.022	1.406754	N
Sulfuric Acid H2SO4	0.2	0.022	27.14633	N

* TLV for coal tar pitch volatiles.
** Ceiling Limit TLV.

2nd Tier Screening (PAIL)

AERMOD air dispersion modeling was performed on the estimated hourly emissions from the following sources, in order to predict ambient concentrations beyond the property boundary. The Presumptively Acceptable Impact Level (PAIL) for each compound has been deemed by the Department to be one one-hundredth of the Threshold Limit Value as listed by the ACGIH.

Pollutant	PAIL ($\mu g/m^3$) = 1/100 of Threshold Limit Value	Modeled Concentration ($\mu g/m^3$)	Pass?
Acrolein	2.292843	0.001082	Y
Arsenic	0.1	0.00165	Y
Benzene	15.97342	0.012893	Y
Benzyl Chloride	51.7586	2.0413E-03	Y
Beryllium	0.0005	0.000402	Y
Cadmium	0.02	0.00049	Y
Chromium	5	0.001099	Y
Chromium VI	0.1	0.00023	Y
Cobalt	0.2	0.000292	Y
Cyanide	51.95951	0.00729	Y
Formaldehyde	3.717791411	4.3318E-02	Y
Hydrogen Chloride	29.83231	3.499433	Y
Hydrogen Fluoride	4.092025	0.437429	Y
Manganese	2	0.002111	Y
Mercury	0.1	0.000583	Y
Methyl Hydrazine	0.188425	0.000496	Y
Nickel	1	0.001157	Y
POM	2	0.002853299	Y
Selenium	2	0.005496	Y
Sulfuric Acid (H_2SO_4)	2	1.066184	Y

Other Modeling:

H_2S Modeling: N/A

13. CALCULATIONS:

SN	Emission Factor Source (AP-42, testing, etc.)	Emission Factor (lb/ton, lb/hr, etc.)	Control Equipment	Control Equipment Efficiency	Comments
SN-01	Coal Fired: NSPS Limits, prior permits,	Coal Fired: CO-300 ppm limit (in 0263-	ESP	99.5%	PM also limited to 0.1 lb/mmbtu by NSPS – this is

SN	Emission Factor Source (AP-42, testing, etc.)	Emission Factor (lb/ton, lb/hr, etc.)	Control Equipment	Control Equipment Efficiency	Comments
	AP-42 (Tables 1.1-4, 1.1-5, 1.1-13, 1.1-14, 1.1-15, 1.1-17 and 1.1-18) Fuel Oil Fired: NSPS Limits Estimated Emissions AP-42 (Tables 1.3-1, 1.3-2, 1.3-3, 1.3-8, 1.3-9, and 1.3-10)	AOP-R0) SO_2: 1.2 lb/MMBTU NO_X: 0.7 lb/MMBTU I hour AP-42 VOC Lead: 0.00042 lb/ton HAPs: various see AP-42 Fuel Oil Fired: AP-42 Lead: 9 lb/10^{12} BTU HAPs: various see AP-42			higher than permitted PM rates
SN-02	Coal Fired: NSPS Limits AP-42 (Tables 1.1-4, 1.1-5, 1.1-13, 1.1-14, 1.1-15, 1.1-17 and 1.1-18) Fuel Oil Fired: NSPS Limits Estimated Emissions AP-42 (Tables 1.3-1, 1.3-2, 1.3-3, 1.3-8, 1.3-9, and 1.3-10)	Coal Fired: CO-300 ppm limit (in 0263-AOP-R0) SO_2: 1.2 lb/MMBTU NO_X: 0.7 lb/MMBTU I hour AP-42 VOC Lead: 0.00042 lb/ton HAPs: various see AP-42 Fuel Oil Fired: AP-42 Lead: 9 lb/10^{12} BTU HAPs: various see AP-42	ESP	99.5%	PM also limited to 0.1 lb/mmBtu by NSPS – this is higher than permitted PM rates

SN	Emission Factor Source (AP-42, testing, etc.)	Emission Factor (lb/ton, lb/hr, etc.)	Control Equipment	Control Equipment Efficiency	Comments
SN-03	Permit Limits AP-42 13.2.4-3 Equation 1	See AP-42 13.2.4-3 Equation 1	Enclosure Chemical Suppressant	50% 90%	VOC based on 1.42% (0.12 lb/gal) with maximum hourly of 91.5 lb/hr and annual of 300,000 lb/yr.
SN-04	Permit Limits AP-42 13.2.4-3 Equation 1	See AP-42 13.2.4-3 Equation 1	Baghouse Enclosure	99.98% PM 99.86% PM_{10}	Two Silos (North and South)
SN-05	AP-42 Tables 1.3-1, 1.3-2, 1.3-3, 1.3-8, 1.3-9, and 1.3-10	Filterable PM/PM_{10}: 2 lb/1000 gal Condensable PM/PM_{10}: 1.3 lb/1000 gal SO_2: 78.5 lb/1000 gal VOC: 0.252 lb/1000 gal CO: 5 lb/1000 gal NO_X: 24 lb/1000 gal Lead: 9 $lb/10^{12}$ BTU HAPs: various see AP-42	N/A	N/A	---
SN-06	AP-42 13.2.4-3 Equation 1 Table 11.9-1 13.2.1.3 Equation 1 13.2.2-2 Equation 1	Various Equations Used See AP-42	Enclosures Chemical Suppressant Baghouse	Up to 80% 90% Up to 99.9% PM 99.8% PM_{10}	VOC based on 1.42% (0.12 lb/gal) with maximum hourly of 91.5 lb/hr and annual of 300,000 lb/yr.

SN	Emission Factor Source (AP-42, testing, etc.)	Emission Factor (lb/ton, lb/hr, etc.)	Control Equipment	Control Equipment Efficiency	Comments
SN-07	Tanks	---	N/A	N/A	112,000,000 gal/yr throughput
SN-14	Tanks	---	N/A	N/A	16,000 gal/yr throughput
SN-15	Tanks	---	N/A	N/A	180,000 gal/yr throughput
SN-16	Tanks	---	N/A	N/A	16,000 gal/yr throughput
SN-17	AP-42 Table 13.4-1	PM: 0.073 lb drift/kgal PM_{10}: 0.073 lb drift/kgal	N/A	N/A	Based on 22,125 kgal/hr circulating water flow and a total dissolved solids content of 2,800 ppm.
SN-18	AP-42 Table 13.4-1	PM: 0.073 lb drift/kgal PM_{10}: 0.073 lb drift/kgal	N/A	N/A	Based on 22,125 kgal/hr circulating water flow and a total dissolved solids content of 2,800 ppm.
SN-19	AP-42 13.2.4 Equation 1 13.2.1 Equation 1 13.2.2 Equation 1a	Various Equation Used See AP-42	Chemical Suppressant on Unpaved Road Wetting and Sweeping Paved Road	90% 95%	6 transfer points: 320 tons coal/hr and 2,733,120 tons coal/yr Paved Roads: 1.9 miles; 12 trips/hr (haul trucks); 2 trips/hr (control equipment) 259,019.4 VMT/yr; 0.99 g silt/m^2 (uncontrolled) Unpaved Roads: 0.25 miles; 12 trips/hr (haul trucks); 1 trip/hr (control equipment) 34,081.5 VMT/yr; 6.8% silt

SN	Emission Factor Source (AP-42, testing, etc.)	Emission Factor (lb/ton, lb/hr, etc.)	Control Equipment	Control Equipment Efficiency	Comments
SN-20	MSDS	6.8 lb VOC/gal	N/A	N/A	1 gal/hr 4,000 gal/yr
SN-21	AP-42	Table 3.4.1 through 3.4-4	None	None	2160 hours annual operation
SN-22	Manufacturer for Criteria Pollutants AP-42 for HAPs	Table 3.3-2 for HAPs	None	None	3000 hours annual operation

14. TESTING REQUIREMENTS:

The permit requires testing of the following sources.

SN	Pollutants	Test Method	Test Interval	Justification
01 and 02	CO	10	Every 5 years	To demonstrate compliance with CO emission rates.
01 and 02	PM	5 and 202	Every year	To demonstrate compliance with PM emission rates.
01 and 02	PM_{10}	201A and 202	Every year	To demonstrate compliance with PM_{10} emission rates.

15. MONITORING OR CEMS:

The permittee must monitor the following parameters with CEMS or other monitoring equipment (temperature, pressure differential, etc.)

SN	Parameter or Pollutant to be Monitored	Method (CEM, Pressure Gauge, etc.)	Frequency	Report (Y/N)
01 & 02	SO_2 CO_2 NO_X Opacity	CEMS	Continuously	Y

16. RECORDKEEPING REQUIREMENTS:

The following are items (such as throughput, fuel usage, VOC content, etc.) that must be tracked and recorded.

SN	Recorded Item	Permit Limit	Frequency	Report (Y/N)
01, 02	SO_2 hourly emissions	10,440.0 lb/hr	Continuously	Y

SN	Recorded Item	Permit Limit	Frequency	Report (Y/N)
01, 02	SO_2 Emissions	1.2 lb/MMBtu	Continuously	Y
01, 02	NO_X hourly emissions	6,090.0 lb/hr	Continuously	Y
01, 02	NO_X Emissions	0.7 lb/MMBtu	Continuously	Y
01, 02	Opacity	20%	Continuously	Y
01, 02	Quarterly Reports	N/A	Quarterly	Y
01, 02	Operating Scenario Log	N/A	As Needed	N
01, 02	SO_2 annual emissions	91,454.4 tpy	Monthly	Y
01, 02	NO_X annual emissions	53,348.4 tpy	Monthly	Y
01, 02	Coal Sulfur and Ash Contents Documentation and (if needed) Calculations	See Specific Condition #26	Annually	N
01, 02, & 05	Sulfur Content of fuel oil	0.5% by weight	Per shipment	N
05	Opacity	20%	Weekly	N
05	Record of when this source is operated	N/A	As Needed	N
06A	Opacity	20%	Weekly	N
06B	Opacity	5% off-site	Weekly	N
03 & 06A	Dust Suppressant Chemical Foam Spray Usage	2.2 tons/12 month	monthly	Y
03 & 06A	MSDS for VOC Content of Chemical Foam Spray	1.42% by weight	as needed	N
03 & 06A	MSDS for HAP Content of Chemical Foam Spray	no HAPs	as needed	N
06	Fly ash trucks vehicle miles traveled on paved roads	63,586 VMT/yr	Monthly	Y
06	Fly ash trucks vehicle miles traveled on unpaved roads	21,507 VMT/yr	Monthly	Y

SN	Recorded Item	Permit Limit	Frequency	Report (Y/N)
06	Operation of Coal Yard Dozers	12,000 hours per yr (combined)	Monthly	Y
06	Water wagon hours of operation	4,000 hours/yr	Monthly	Y
06	Cat Scraper hours of operation	1,500 hours/yr	Monthly	Y
04	Opacity	20%	Daily	Y
04	Log of baghouse maintenance inspections	N/A	Semi-annually	N
07	Fuel Oil Throughput	112,000,000 gal/yr	Monthly	Y
14	Fuel Throughput	16,000 gallons/yr	Monthly	Y
15	Fuel Throughput	180,000 gallons/yr	Monthly	Y
16	Fuel Throughput	16,000 gallons/yr	Monthly	Y
17, 18	Total dissolved solids	2,800 ppm	Weekly	N
17, 18	Circulating water	22,125 kgal/hr	Annually	N
19	Coal Throughput	2,733,120 tons/yr	Monthly	Y
19	Vehicle miles traveled on paved roads from barge to coal pile	259,019.4 VMT/yr	Monthly	Y
19	Vehicle miles traveled on unpaved roads from barge to coal pile	34,081.5 VMT/yr	Monthly	Y
19	MSDS for VOC Content of chemical suppressant	No VOC	As Needed	N
19	MSDS for HAP Content of chemical suppressant	No HAP	As Needed	N
20	MSDS for VOC content	6.8 lb/gal	As Needed	N
20	Solvent Throughput	4,000 gal/yr	Monthly	Y
21	Hours of operation	2160 hrs/12 month	Monthly	Y
22	Hours of operation	3000 hrs/12 month	Monthly	Y

17. OPACITY:

SN	Opacity	Justification for limit	Compliance Mechanism
01, 02	20%, 27%	NSPS limit, Department Guidance	COM
01, 02	20%, 60%	State limit	COM
01, 02	20%	CAM (1-hr and 3-hr averages)	COM
03	20%	Department Guidance	Water/Chemical Foam Spray
04	20%	Department Guidance	Daily Observation
05	20%	Department Guidance	Weekly Observation
06A	20%	Department Guidance	Weekly Observation
06B	5% off-site	Department Guidance	Weekly Observation
17, 18	20%	Department Guidance	Operate within Design Specification
19	5% off-site	Department Guidance	Inspections
21	20%	Department Guidance	Once per year and daily if operated more than 24 hours
22	20%	Department Guidance	Once per year and daily if operated more than 24 hours

18. DELETED CONDITIONS:

There were no deleted conditions with this permit revision.

19. GROUP A INSIGNIFICANT ACTIVITIES:

Source Name	Group A Category	Emissions (tpy)						
		PM/PM_{10}	SO_2	VOC	CO	NO_x	HAPs	
							Single	Total
C6a Microwave Tower Propane Generator	A1	1.5E-03	4.4E-05	2.2E-03	1.6E-02	2.8E-02		
C6b Microwave Tower Propane Generator	A1	1.5E-03	4.4E-05	2.2E-03	1.6E-02	2.8E-02		

Source Name	Group A Category	Emissions (tpy)						
		PM/PM_{10}	SO_2	VOC	CO	NO_x	HAPs	
							Single	Total
C7 Kerosene Fired Space Heater (12 total)	A1	4.4E-03	3.9E-02	0.0E+00	0.0E+00	1.1E-02		1.9E-03
Total			3.95E-02	4.38E-03	3.29E-02	6.79E-02		1.85E-03
T6 Unit 1 FD Fan Hydraulic Reservoir	A2			1.45E-07				
T7 Unit 1 FD Fan Lube Oil Reservoir	A2			1.45E-07				
T8 Unit 1 ID Fan Hydraulic Oil Reservoir	A2			6.99E-08				
T9 Unit 1 ID Fan Motor Oil Reservoir	A2			3.29E-05				
T10 Unit 1 ID Fan Lube Oil Reservoir	A2			6.99E-08				
T15 Unit 2 ID Fan Hydraulic Oil Reservoir	A2			6.99E-08				
T16 Unit 2 ID Fan Motor Oil Reservoir	A2			6.99E-08				
T17 Unit 2 ID Fan Lube Oil Reservoir	A2			6.99E-08				
T18 Unit 2 FD Fan Lube Oil Reservoir	A2			1.43E-07				
T19 Unit 2 FD Fan Hydraulic Reservoir	A2			1.43E-07				
T96 Unit-1 Lube Purifier/Centrifuge	A2			6.99E-08				
T97 Unit-2 Lube Purifier/Centrifuge	A2			6.99E-08				
T98 Vacuum Pump Oil Separator (2)	A2			1.40E-07				
T99 No. 1A & 1B BFPT Lube Oil Reservoir	A2			1.43E-07				
T100 No. 2A & 2B BFPT Lube Oil Reservoir	A2			1.43E-07				
T114 Bowl Mill	A2			4.16E-				

Source Name	Group A Category	Emissions (tpy)						
		PM/PM_{10}	SO_2	VOC	CO	NO_x	HAPs	
							Single	Total
Lube Oil Storage Tanks (4)				06				
T123 Stacker/Reclaimer Lube Oil Storage Tank	A2			1.04E-06				
T124 Vacuum Pump Lube Oil Storage Tanks (2)	A2			3.07E-06				
T125 Lube Oil House Storage Tanks (2)	A2			1.75E-06				
T126 APH Gear Box Lube Oil Tanks (2)	A2			8.35E-07				
Total				4.52E-05				
T4 Unit 1 EHC Reservoir	A3			2.68E-06				
T5 No. 1 A & 1B BFPT Lube Oil Reservoir	A3			3.51E-06				
T13 Unit 2 EHC Reservoir	A3			2.75E-06				
T14 No. 2A & 2B BFPT Lube Oil Reservoir	A3			3.95E-04				
T21 Used Oil Double Walled Storage Tank	A3			2.79E-05				
T22 Portable Used Oil Collection Bulk Containers (3)	A3			5.79E-06				
T24 Mobile Used Oil Storage Tank	A3			1.34E-05				
T27 Mobile Diesel Fuel Storage Tank*	A3			1.09E-04				
T29 Emergency Fire Pump Diesel Fuel Storage Tank	A3			1.60E-04				
T30 Emergency	A3			1.40E-				

Source Name	Group A Category	Emissions (tpy)						
		PM/PM_{10}	SO_2	VOC	CO	NO_x	HAPs	
							Single	Total
Diesel Generator Fuel Tank				04				
T31 Portable Kerosene Storage Skid Tank	A3			1.83E-04				
T94 Unit 1 Hydrogen Seal Tank	A3			1.75E-06				
T95 Unit 2 Hydrogen Seal Tank	A3			1.75E-06				
T121 RCD Hydraulic Oil Reservoir-1	A3			3.89E-07				
T122 RCD Hydraulic Oil Reservoir-2	A3			1.76E-06				
T113 Miscellaneous Paint Containers Storage	A3			1.17E-04				
T115 Coal Yard Lube Oil, Antifreeze, and Hydraulic Fluid Storage Tanks (3)	A3			1.27E-05				
T116 Vehicle Maintenance Lube Oil, Antifreeze and Hydraulic Fluid Storage Tanks (3)	A3			1.27E-05				
T120 Main Oil/Water Separator Used Oil Vault	A3			2.68E-05				
T127 Skid Mounted Horizontal Diesel Tank	A3			1.12 E-03				
TOTALS				2.42 E-03				
T2 Unit 1 Turbine Lube Oil Storage Tank	A13			3.66E-05				
T3 Unit 1 Turbine	A13			2.09E-				

Source Name	Group A Category	Emissions (tpy)						
		PM/PM$_{10}$	SO_2	VOC	CO	NO_x	HAPs Single	HAPs Total
Lube Oil Reservoir				05				
T11 Unit 2 Turbine Lube Oil Storage Tank	A13			3.66E-05				
T12 Unit 2 Turbine Lube Oil Reservoir	A13			2.09E-05				
T51 Units 1&2 Glycol Air Preheater Expansion Tanks (4)	A13			3.55E-06				
T53 Unit 1&2 Glycol Mixing Tanks (2)	A13			1.14E-06				
T54 Ethylene Glycol Storage Tank	A13			4.10E-05				
T57 Unit 1 Glycol Mixing Tank	A13			5.70E-07				
T58 Unit 1 Hydrazine Mixing Tank	A13			3.96E-07				
T59 Hydrazine Solution Bulk Containers	A13			4.27E-07				
T71 EHC Fluid Storage	A13			1.07E-07				
X10 & 11 Welding Areas - Machine Shop & Bowl Mill Shop	A13	2.25E-01					8.17E-02 (max)	2.18E-01
X15 Unleaded Gasoline Dispensing Station	A13			2.43E-01				
X16 Diesel Dispensing Station (2)	A13			4.87E-01				
X22 Sand Blasting Booth	A13							
X31 Unit 1 ESP Transformer/Rectifiers X32 Unit 2 ESP Transformer/Rectifie	A13							

Source Name	Group A Category	Emissions (tpy)						
		PM/PM_{10}	SO_2	VOC	CO	NO_x	HAPs	
							Single	Total
rs X33 Spare Transformers / Rectifiers X34 Transformers Switchyard X35 Transformers & Oil Circuit Breakers								
X36-X54 AC Chiller Units	A13							
X55 Aerosol Lubricant Fugitives	A13			4.38E-02			1.53E-02	1.53E-02
X56 Aerosol Degreaser Fugitives	A13			1.89E-01				
M60 Unit 1 Economizer Ash Silo	A13	1.16E-01						
M61 Unit 2 Economizer Ash Silo	A13	1.16E-01						
X57 Unit 1 AC Silo	A13	0.004						
X58 Unit 2 AC Silo	A13	0.004						
Total		4.65E-01		9.63E-01				2.33E-01

20. VOIDED, SUPERSEDED, OR SUBSUMED PERMITS:

List all active permits voided/superseded/subsumed by the issuance of this permit.

Permit #
0263-AOP-R7

APPENDIX A – EMISSION CHANGES AND FEE CALCULATION

Fee Calculation for Major Source

Revised 11-06-13

Facility Name: Entergy Arkansas, Inc. (White Bluff Plant)
Permit Number: 263-AOP-R8
AFIN: 35-00110

$/ton factor	23.42	Annual Chargeable Emissions (tpy)	17136.516
Permit Type	Modification	Permit Fee $	1000

Minor Modification Fee $	500
Minimum Modification Fee $	1000
Renewal with Minor Modification $	500
Check if Facility Holds an Active Minor Source or Minor Source General Permit	
If Hold Active Permit, Amt of Last Annual Air Permit Invoice $	0
Total Permit Fee Chargeable Emissions (tpy)	0
Initial Title V Permit Fee Chargeable Emissions (tpy)	

HAPs not included in VOC or PM: *Chlorine, Hydrazine, HCl, HF, Methyl Chloroform, Methylene Chloride, Phosphine, Tetrachloroethylene, Titanium Tetrachloride*

Air Contaminants: *All air contaminants are chargeable unless they are included in other totals (e.g., H2SO4 in condensible PM, H2S in TRS, etc.)*

Pollutant (tpy)	Check if Chargeable Emission	Old Permit	New Permit	Change in Emissions	Permit Fee Chargeable Emissions	Annual Chargeable Emissions
PM		6680.8	6607	-73.8	0	4000
PM_{10}		6429.8	6414.8	-15		
SO_2		91920.7	91920.7	0	0	4000
VOC		327.6	327.6	0	0	327.6
CO		28482.4	28482.4	0		
NO_X		53520.4	53520.4	0	0	4000
Lead		2.1	2.1	0		
2,3,7,8-TCDD		6.58E-08	6.58E-08	0		

Pollutant (tpy)	Check if Chargeable Emission	Old Permit	New Permit	Change in Emissions	Permit Fee Chargeable Emissions	Annual Chargeable Emissions
2-Chloroacetophenone	☐	0.0322	0.0322	0		
Acetaldehyde	☐	2.62498	2.62498	0		
Acrolein	☐	1.334403	1.334403	0		
Arsenic	☐	1.889217	1.889217	0		
Benzene	☐	5.991556	5.991556	0		
Benzyl Chloride	☐	3.22	3.22	0		
Beryllium	☐	0.09684	0.09684	0		
Cadmium	☐	0.237013	0.237013	0		
Carbon Disulfide	☐	0.598	0.598	0		
Chloroform	☐	0.2714	0.2714	0		
Chromium	☐	1.198413	1.198413	0		
Chromium VI	☐	0.3634	0.3634	0		
Cobalt	☐	0.46	0.46	0		
Cyanide	☐	11.5	11.5	0		
Dimethyl Sulfate	☐	0.2208	0.2208	0		
Ethylene Dichloride	☐	0.184	0.184	0		
Formaldehyde	☐	3.35588	3.35588	0		
Hydrogen Chloride	☑	5520	5520	0	0	4000
Hydrogen Fluoride	☑	690	690	0	0	690
Isophorone	☐	2.668	2.668	0		
Manganese	☐	2.258825	2.258825	0		
Mercury	☐	0.384213	0.384213	0		
Methyl Chloride	☐	2.438	2.438	0		
Methyl Hydrazine	☐	0.782	0.782	0		
Nickel	☐	1.290413	1.290413	0		
Phenol	☐	0.0736	0.0736	0		
POM	☐	0.230377	0.230377	0		
Propionaldehyde	☐	1.748	1.748	0		

Pollutant (tpy)	Check if Chargeable Emission	Old Permit	New Permit	Change in Emissions	Permit Fee Chargeable Emissions	Annual Chargeable Emissions
Selenium	☐	5.992062	5.992062	0		
Sulfuric Acid H2SO4	☑	118.916114	118.916114	0	0	118.91611

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Via U.S. Mail and e-mail July 11, 2014

Teresa Marks, Director
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, Arkansas 72118-5317
Attention: ADEQ Air Permits Branch
airpermits@adeq.state.ar.us

Re: ***Sierra Club Comments on the Proposed Modification to the Title V Operating Permit for Entergy-Arkansas, Inc.'s White Bluff Plant, Draft Operating Air Permit (Permit No.: 0263-AOP-R8)***

Dear Ms. Marks:

I am submitting the following comments on behalf of the Sierra Club on the proposed modification to the Title V Operating Permit for Entergy-Arkansas, Inc.'s ("Entergy") White Bluff Plant, which has been designated as Draft Operating Air Permit (Permit No.: 0263-AOP-R8) (hereinafter "Draft White Bluff Permit"). In addition to these written comments, Sierra Club has attached a number of exhibits which are all expressly incorporated by reference into this document and support the comments made herein.

The Sierra Club is the nation's oldest environmental organization. It has more than 2.4 million members and supporters nationwide and is dedicated to the protection and preservation of the natural and human environment. Among other environmental concerns, the Sierra Club is focused on addressing the pressing environmental and health problems associated with the mining, burning, and disposal of coal and its combustion by-products. Sierra Club's national office is located at 85 Second Street, San Francisco, California 94105. The office of the Arkansas Chapter of Sierra Club is located at 1308 West 2nd Street, Little Rock, Arkansas 72201. In Arkansas, Sierra Club has thousands of members, many of whom are negatively affected by emissions from the White Bluff Plant. The Sierra Club and its many impacted members are "interested persons" in regard to this proposed permitting action. Sierra Club members in Arkansas (and elsewhere) have a strong interest in ensuring that the White Bluff Plant fully complies with the applicable air quality regulations and that both Entergy and Arkansas

Department of Environmental Quality ("ADEQ") strictly adhere to Arkansas's substantive and procedural rules governing modifications to air operating permits.

These comments are being submitted on the last day of the public comment period for this permitting action. Your office has, however, granted Sierra Club's request for a public hearing, which is scheduled for August 14, 2014. Sierra Club is still in the process of obtaining numerous documents from the ADEQ that are highly relevant to many issues implicated by this permitting action through Arkansas's Freedom of Information Act. Ark. Code Ann. § 25-19-101 *et seq.* Accordingly, Sierra Club's analysis is continuing and the comments provided below are to some extent preliminary. Sierra Club plans to participate in the August 14th public hearing on this matter and intends to submit more refined and comprehensive written and oral comments at that hearing, based in part on a more refined analysis of the additional documentation that it seeks from ADEQ.

I. The Technical Justification for the Proposed ACI Project and the Claim That this Project Will Not Increase Particulate Matter ("PM") Emissions Is Flawed and Incomplete and, In Fact, PM-10 Emissions Are Likely To Exceed the PSD Significance Levels and Trigger the Requirement to Obtain a Prevention of Significant Deterioration ("PSD") Permit and Apply Best Available Control Technology ("BACT")

The Sierra Club has retained an expert with extensive experience evaluating coal plant operations, Dr. Ranajit (Ron) Sahu, to evaluate Entergy's assertion that particulate matter emissions will decrease following the addition of activated carbon injection ("ACI") to its operations at White Bluff. Dr. Sahu's Preliminary Report on this issue is attached as Exhibit 1, and his observations and conclusions are hereby incorporated into this comment letter.

Among other things, Dr. Sahu concludes that Entergy's technical support for its ACI project is fundamentally flawed in numerous ways, and is based on unreliable and insufficient technical information and documentation. Without much more reliable and comprehensive technical support for this project, ADEQ cannot reasonable accept Entergy's assertion that particulate matter emissions will decrease as a result of the addition of ACI. On the contrary, based upon the available evidence, Dr. Sahu concludes that the filterable PM from the proposed ACI project will likely cause a collective increase of filterable PM of approximately 22.8 tons per year, which is sufficient to trigger PSD applicability and the requirement to apply BACT. On this basis alone, the Draft White Bluff Permit cannot lawfully be issued.

As Dr. Sahu concisely points out in his preliminary report:

> What is clear is that with ACI addition, the particulate loading into the ESPs will increase. The Road Emission Calculations spreadsheet provided by Entergy states that the maximum annual ACI Injection Rate (or usage) will be 2,278 tons/year for both units. Assuming an ESP filterable PM efficiency of 99%

> (which is generous, given the total lack of information on ESP design, condition, and operating parameters) for each ESP, the incremental emissions of filterable PM as a result of the additional ACI loading is approximately 2,278*(1-0.99) = 22.8 tons/year. In addition, as Entergy notes, there are additional increases in fugitive PM emissions as a result of road traffic, ash hauling, ACI transport, etc. Collectively, the expected increase in filterable PM emissions, therefore, is likely above 22.8 tons/year. This exceeds the PSD Significant Emissions Rate for PM_{10}, which is 15 tons/year.[1] Thus, it is more likely than not that the addition of ACI, as proposed by Entergy for White Bluff Units 1 and 2, will trigger PSD review for this pollutant. This means that the application and permit are incomplete, since Entergy has not provided a BACT analysis, or any ambient air quality modeling analysis, or any of the other PSD application requirements (such as impacts to Air Quality Related Values), *etc*.

Id. at 5.

Sierra Club contends that, based upon the available evidence, there is no basis for ADEQ to accept Entergy's assertion that particulate matter emissions will decrease. In fact, that the addition of ACI will likely increase PM emissions at White Bluff sufficient to trigger PSD review for this pollutant. For these and all the reasons discussed in Dr. Sahu's preliminary report, the Draft White Bluff Permit cannot lawfully be issued.

II. The Draft White Bluff Permit Cannot Lawfully Be Issued Because No Adequate Demonstration Has Been Performed, and ADEQ Has No Reasonable Basis for Concluding, That the White Bluff Plant and the Proposed Changes to be Made Thereto Will Not Result in Interference With Attainment of the NAAQS

As addressed above, the proposed ACI project covered by the Draft White Bluff Permit is likely to result in an increase in PM emissions that is sufficient to trigger PSD applicability. Nearby Pulaski County, Arkansas is currently on the brink of exceeding the new annual $PM_{2.5}$ National Ambient Air Quality Standard ("NAAQS") primary standards and may well be designated as non-attainment for that standard in 2014. See 12/5/13 Letter from Gov. Mike Beebe to EPA Regarding NAAQS designations.[2] In light of surrounding ambient air quality, ADEQ must ensure that any modified permits for major sources of particulate matter do not interfere with attainment of the NAAQS.

In addition, SO_2 modeling that Sierra Club has performed has revealed that the White Bluff plant's allowable and actual SO_2 emissions are causing violations of the 1-hour average NAAQS for SO_2. *See* AERMOD Modeling of SO_2 Impacts of the Entergy White Bluff Coal Plant, prepared for Sierra Club by Khanh T. Tran, AMI Environmental, September 28, 2011, at 6 (Table 2) (Ex. 2). Despite these facts, neither

[1] 40 C.F.R. § 52.21(b)(23)(i)

[2] http://epa.gov/airquality/particlepollution/designations/2012standards/rec/r6arrec1.pdf

ADEQ nor anyone else has performed any air modeling analysis or other comparable demonstration to show that the White Bluff Plant and the proposed modification projects covered by the Draft White Bluff Permit will not interfere with attainment of the NAAQS or otherwise cause air pollution that is harmful to human health. For this reason, the Draft White Bluff Permit cannot be lawfully issued.

There are many provisions in state law, the Clean Air Act, and the Arkansas SIP that require air modeling in this situation or at least some substantive demonstration that NAAQS attainment will not be interfered with and that injurious air pollution will not result as a consequence of this permit. *See* APCEC Reg. 18.302; APCEC Reg. 19.402; APCEC Reg. 19.502; APCEC Reg. 26; Clean Air Act Section 110(a)(2)(C); 40 C.F.R. § 51.160-51.164.

Sierra Club understands that in April 2013, the Arkansas Legislature and governor enacted a new law, Act 1302, that prohibits ADEQ from requiring a permit applicant to submit air quality modeling to demonstrate compliance with the NAAQS, and prohibits ADEQ from undertaking its own modeling or even considering modeling submitted by a third-party without the applicant's consent. This law does contain exceptions for new source applications and sources subject to PSD review. Sierra Club's understanding is that ADEQ's previous practice of conducting air quality modeling for Title V permit renewals was integral to ADEQ's strategy for assuring compliance with the NAAQS. Indeed, Act 1302 now requires ADEQ to develop "NAAQS state implementation plans," presumably to fill the gap left in Arkansas's plan for assuring compliance with the NAAQS once ADEQ is no longer permitted to follow its previous practices. EPA has also expressed concern about the implications of Act 1302 for Arkansas's legal authority to ensure attainment of the NAAQS.

In its Statement of Basis for this permit, ADEQ explains that pursuant to Act 1302, no air dispersion modeling was performed, and that "criteria pollutants were not evaluated for impacts on the NAAQS." (Statement of Basis at p. 3). Combined with the flawed PSD applicability analysis submitted by Entergy, ADEQ has not satisfied state law and SIP requirements to ensure that the NAAQS are attained and that public health is protected. This deficiency must be corrected, and ADEQ must issue a revised draft permit for public review.

III. The Draft White Bluff Permit Should Not Be Issued Due to a Lack of Enforceability and Specificity Concerning the Identification and Description of the Proposed Air Pollution Control Equipment and Applicable Requirements

The purpose of a Title V operating permit is, in part, to allow the public to assess a facility's compliance with all applicable requirements. *See generally* APCEC Reg. 26.402(B)(3) (e)-(h), (4), (5) and (7). The new Mercury and Air Toxics Standards ("MATS") will be applicable requirements for this facility beginning in April 2016. As you know, EPA's MATS regulation allows sources to comply in several different ways; for example, a source can choose to comply with either a limit on sulfur dioxide (SO_2)

or acid gases (HCl). However, this choice cannot be an ongoing one without undermining the very purpose of Title V. *See, e.g., Sierra Club v. Johnson*, 541 F.3d 1257, 1260 (11th Cir. 2008) (Title V added "clarity and transparency" to the permitting process "to help citizens, regulators, and polluters themselves understand which clean air requirements apply to a particular source of air pollution."); *see id.* ("The goal is 'increased source accountability and better enforcement.'") (quoting "Operating Permit Program," 57 Fed. Reg. 32250, 32,251 (July 21, 1992)).

The Draft White Bluff permit incorporates the MATS limits in Section IV, ¶¶ 29-33, retaining the "either/or" option for the three different basic categories of MATS limits. Such a permit structure materially deprives the public of an opportunity to track the plant's compliance. Under this framework, the facility is effectively free to choose (even, perhaps, years after the fact) among the alternative compliance methods on its own without any notice to ADEQ or the public. These permit conditions are therefore unenforceable. ADEQ should require Entergy to incorporate into the Draft White Bluff Permit the specific MATS limits for which it intends to comply or should otherwise refuse to issue the permit.

IV. The Draft White Bluff Permit is Unlawful and Should Not Be Issued Because It Unlawfully Fails to Include or Unlawfully Relaxes or Revises Federally Enforceable SIP Limitations on Opacity Applicable to White Bluff Units 1 and 2

All sources subject to Title V permitting must have a permit to operate "that assures compliance by the source with all applicable requirements." *See* 40 C.F.R § 70.1(b); CAA Section 504(a), 42 U.S.C. § 766lc(a); APCEC Reg. 26.701(A) and 26.102. Applicable requirements are defined in APCEC Reg. 26, Chapter 2, to include: "(1) any standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under Title I of the [Clean Air] Act," which includes the EPA-approved Arkansas SIP limitations on opacity from the boilers at Units 1 and 2 set forth at APCEC Reg. 19, 503(B)(1). *See also* 40 C.F.R. § 70.2; *see generally* Clean Air Act Section 110(a)(2)(C), 42 U.S.C. 7410(a)(2)(C); Clean Air Act Sections 160-69, 42 U.S.C. §§ 7470-7492 ; Clean Air Act Section 173, 42 U.S.C. § 7503; 40 C.F.R. §§ 51.160-66 & 52.21. As explained below, the Draft White Bluff Permit creates a hybrid opacity limit that combines and modifies the Arkansas SIP's opacity limit and the NSPS Subpart D opacity and fails to properly identify and articulate the full contours of the Arkansas SIP opacity limit as an applicable requirement. The manner in which the Draft Permit articulates the hybrid limit results in an unlawful relaxation or revision of the federally enforceable Arkansas SIP opacity limit applicable to White Bluff Units 1 and 2. For that reason, the Draft White Bluff Permit cannot be lawfully issued.

A. <u>The Importance of Opacity Limits and the Relationship Between Opacity and PM Emissions</u>

Restrictions on opacity or visible emissions are one of the most basic emission limitations imposed on sources of air pollution. "'Opacity' means the degree to which air emissions reduce the transmission of light and obscure the view of an object in the background." APCEC Reg. 19, Chapter 2, Definitions; *see also Sierra Club v. EPA*, 430 F.3d 1337, 1341 (11th Cir. 2005).

> For example, a plume with 20% opacity blocks 20% of light passing through it; no light passes through a plume with 100% opacity. Opacity is not a pollutant, but instead is a measure of the light-blocking property of a plant's emissions, which is important in the Clean Air Act regulatory scheme as an indicator of the amount of visible particulate pollution being discharged by a source.

Id.

Every state, including Arkansas, maintains a SIP to "enforce national ambient air quality standards developed by EPA." *Id.* (citing 42 U.S.C. § 7410). Each State Implementation Plan, in turn, must have regulations that limit visible emissions or opacity. 40 C.F.R. § 51.212(b).

An important reason for this opacity regulation requirement is that large sources of air pollution, such as the White Bluff units, can emit an astonishing amount of particulate matter (PM) pollution in a short amount of time. Fortunately, modern pollution controls are capable of reducing these emissions by over 99%. Jacob Katz,P.E., The Art of Electrostatic Precipitation, S&S Printing Company, Pittsburgh, 1981, p.332 (when operating properly, four-field ESPs have expected efficiencies in the range of 99.0 to 99.3 percent).

To keep particulate pollution under control, it is imperative that these highly efficient control devices operate continuously, as required by the Clean Air Act. *Sierra Club v. EPA*, 430 F.3d at 1348. Until recently, however, it has been impossible to know whether PM emission limits are being complied with continuously. Historically, regulators have relied on a two-step control scheme. First, regulators have required elaborate, expensive, and infrequently performed tests that demonstrate that a source can, when operating its pollution controls, comply with PM emission limits. 39 Fed. Reg. 9308, 9309 (March 8, 1974). Second, regulators have imposed opacity standards. Opacity can be evaluated on an instantaneous and continuous basis, thereby providing critical insight into whether pollution controls are being properly maintained and operated.

As EPA recently stated in a final rule disapproving an Alabama SIP revision request relating to opacity:

Historically, visible emissions have been an important tool for implementation of PM NAAQS and, in particular, for the implementation and enforcement of PM limits on sources to help attain the NAAQS.[] Visible emissions have been a useful tool to indicate overall operation and maintenance (O & M) of a facility and its emissions control devices even before modern instruments that measure PM on a direct, continuous basis existed. The observation of greater than normal visible emissions, particularly on a recurring basis, has served as an indication that incomplete combustion or other changes to the process and/or the control device had or were occurring; such changes frequently led to increased PM emissions. Although opacity is not a criteria pollutant, opacity standards continue to be used as an indicator of the effectiveness of emission controls for PM emissions, or to assist with implementation and enforcement of PM emission standards for purposes of attaining PM NAAQS. Opacity measurements can serve as an indicator of a well-maintained, well-operated source and that such sources should be able to achieve visible emissions that comply with opacity limits.

76 Fed. Reg. 18870, 18,872 (April 6, 2011).

To ensure the effectiveness of this approach, at the dawn of clean air regulation, EPA determined that it was best to make opacity an independently enforceable requirement. 39 Fed. Reg. at 9309. And since approximately the mid-1970's, the state of Arkansas has imposed an opacity limit.

B. The Arkansas SIP's Opacity Regulations

The current Arkansas SIP regulation governing opacity is found at APCEC Reg. 19.503 and was most recently approved by EPA on April 12, 2007. 72 Fed. Reg. 18394 (April 12, 2007). It reads in pertinent part as follows:

Section 19.503 Visible emission regulations

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(B) No person shall cause or permit visible emissions (other than uncombined water vapor) from new equipment identified hereinunder which was installed or permitted by the Department after January 30, 1972 to exceed the following limitations or to exceed any applicable visible emission limitations of the New Source Performance Standards promulgated by the United States Environmental Protection Agency:

(1) ***For incinerators and fuel burning equipment, exclusively, emissions shall not exceed 20% opacity except that emissions greater than 20% opacity but not exceeding 60% opacity will be allowed for not more than six (6) minutes in the aggregate in any consecutive 60-minute period, provided such emissions will not be permitted more than three (3) times during any 24-hour period.***

(2) For equipment used in a manufacturing process, emissions shall not exceed 20%.

(C) Opacity of visible emissions shall be determined using EPA Method 9 (40 CFR Part 60, Appendix A).

(emphasis added).

The opacity limit set forth at APCEC Reg. 19.503(B)(1) is part of the federally enforceable SIP and governs opacity emissions from White Bluff Units 1 and 2. Significantly, this provision limits opacity from White Bluff Units 1 and 2 to 20% except for three six (6) minute periods in the aggregate in any consecutive 60-minute period so long as those periods do not exceed 60% opacity. *Id.* And this provision does not contain any exemptions for startups, shutdowns, malfunctions or upsets. *Id.*

The Arkansas SIP also contains two provisions relating to upset and emergency conditions. The upset conditions provision set forth at APCEC Reg. 19.601makes clear that this provision merely sets forth the limited conditions under which ADEQ may choose, in an exercise of enforcement discretion, to forego the pursuit of an enforcement action for emission limit violations when an "upset" (which could include startup and shutdowns if they are due to physical constraints the prevent a source from complying with an applicable limit) as defined by this rule has occurred and when all the other specifically delineated conditions have been satisfied. APCEC Reg. 19.601 ("The Department may forego enforcement action for federally regulated air pollutant emissions given that the person responsible for the source of the excess emissions does the following:" [setting out conditions of enforcement discretion]) This provision does not in any manner modify any aspects of a federally enforceable SIP emission limit, including the opacity limitation set forth at APCEC Reg. 19.503(B)(1).

To the contrary, as the rule clearly states, "[a]ny source exceeding an emission limit established by the Plan or applicable permit shall be deemed in violation of said Plan or permit and shall be subject to enforcement action." *Id.* In other words, the upset rule does not provide an automatic exemption from the SIP opacity limit (or any other limitation), *see* 1/20/05 E-mail from ADEQ's A. Sudmeyer to Entergy's G. Johnson (confirming that for compliance purposes there are no automatic exemptions from Arkansas' 20% opacity limitation) and the fact that a qualifying upset, including a startup or shutdown, occurs does not excuse the exceedance from being a violation as a matter of law. Since the opacity standard at APCEC Reg. 19.503(B)(1) does not exempt startups and shutdowns (or upsets, malfunctions, or emergencies for that matter) from the applicable opacity limit, opacity exceedances are violations even when they occur during startups and shutdowns.

Consequently, it also necessarily follows that any decision by ADEQ to forego an enforcement action for an opacity violation occurring during an upset, including a startup or shutdown, does not preclude or prevent EPA or any citizen from taking an enforcement action over the same violation. *See generally* EPA's 1999 Policy

Regarding Excess Emissions During Malfunctions, Startup, and Shutdown ("EPA's SSM Policy") at pdf 3, 6.[3]

The Arkansas SIP also contains a provision purporting to address emergency conditions. That provision is set forth at APCEC Reg. 19.602 and contains conditions for establishing the exemption that are generally more difficult to satisfy than the upset rule. In order to be applicable, a sudden, reasonably unforeseeable event beyond the control of the source that requires immediate corrective action to restore normal operation must occur which causes the source to exceed a technology-based emission limitation[4] due to unavoidable increases in emissions attributable to the event in question. However, where all the conditions are met for its application, including, the submission of a report by the end of the following business day, this provision purports to establish an affirmative defense to any enforcement action addressing violations covered by the emergency provision where an emergency condition as defined in the rule has occurred and all the other specified conditions are fully satisfied.[5] Assuming, *arguendo*, that this provision has potential application to exceedances of the federal enforceable Arkansas SIP's opacity limit at Reg. 19.503, it may, when all the required conditions are met, be relied on to bar any enforcement action over covered exceedances of the Arkansas SIP's opacity limit which are still technically violations of that limit.

C. <u>The NSPS Subpart D Opacity Limit Applicable to White Bluff Units 1 and 2</u>

In addition to the Arkansas SIP's opacity limit at APCEC Reg. 19.503(B)(1), White Bluff Units 1 and 2 are also subject to a different opacity limit imposed by NSPS Subpart D, 40 C.F.R. 60.42(a)(2). Specifically, the NSPS Subpart D opacity limit states in pertinent part that:

> no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that ...[e]xhibit ***greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity***.

Id. (emphasis added).

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[3] http://www.epa.gov/ region07/air/ title5/t5memos/excesem2.pdf

[4] The fact that this emergency provision is limited to violations of technology-based emission limitations calls into question whether it is applicable to the Arkansas SIP's opacity limitation. The opacity SIP provision is a requirement designed to assist Arkansas in complying with the PM NAAQS, which is an air quality-based standard, unlike the emission limits set forth in NSPS Subpart D, which are technology-based standards. Consequently, the emergency condition provision at APCEC Reg. 19.602 is not likely applicable to the Arkansas SIP's opacity limit at all.

[5] This SIP provision appears to be inconsistent with EPA's SSM Policy and otherwise unlawful.

Unlike the SIP opacity limit, this NSPS opacity limit incorporates absolute exceptions for startup, shutdown, and malfunction set forth in 40 C.F.R. § 60.11(c).

D. <u>The Draft White Bluff Permit is Unlawful Because it Fails to Identify the Arkansas SIP's Opacity Limit as a Fully and Independently Applicable Requirement in Addition to NSPS Subpart D Opacity Limit and Because the Hybrid Opacity Limitation Created in the Permit at Condition No. 28 is Less Stringent Than Either the Arkansas SIP Opacity Limit or the NSPS Subpart D Opacity Limit</u>

At Condition 3.b of the Draft White Bluff Permit (page 19), the NSPS Subpart D opacity limit at 40 C.F.R. § 60.42(a)(2) (including exemptions in 40 C.F.R. § 60.8 and 60.11) is set forth as an applicable requirement for White Bluff Units 1 and 2. This standard is reflected in other provisions of the permit pertaining to Units 1 and 2 as well. However, instead of also identifying and accurately describing the other federally enforceable opacity limitation applicable to White Bluff Units 1 and 2, that is, the Arkansas SIP opacity limit at APCEC Reg. 19.503(B)(1), the Draft White Bluff Permit identifies that SIP opacity limit only to immediately sublimate that limit and expressly hold it in abeyance in favor of a modified or hybrid version of the NSPS Subpart D opacity limit. Draft White Bluff Permit, Condition 28, at pdf 26-27.

Specifically, after the recitation of the Arkansas SIP opacity limit, Specific Condition 28 states in pertinent part:

> However, the opacity limits imposed by this condition will be held in abeyance provided that opacity does not exceed 20% except that emissions greater than 20% opacity but not exceeding 27% opacity will be allowed for not more than one 6-minute period per hour, provided such emissions will not be permitted more than ten (10) times per day. ***Violations of this condition may be allowed as a direct result of unavoidable upset conditions in the nature of the process, or unavoidable and unforeseeable breakdown of any air pollution control equipment or related operating equipment, or as a direct result of shutdown or start-up of the operating unit,[[6]] provided the following requirements are met***: . . . .

[6] Parts of this hybrid opacity limit -- the exemption for startups, shutdowns and malfunctions -- reflects standard NSPS exclusions from the opacity standard. 40 C.F.R. § 60.11(c). However, this provision also articulates new unlawful absolute exemptions which provide for the allowance of violations occurring as a result of (1) upset conditions in the nature of the process and (2) unavoidable and unforeseeable breakdowns of control or operating equipment. Although these exemptions appear to have been derived to some extent from the "upset conditions" and "emergency conditions" provisions of the SIP at APCEC Reg. 19.601 and 19.602, their language does not precisely track either the Arkansas SIP or NSPS Subpart D. As expressed in the hybrid opacity limit at Specific Condition 28, the "upset conditions" provision of the Arkansas SIP appears to have morphed from a description of how enforcement

Draft White Bluff Permit at 29-30 (emphasis added).

As drafted, this provision appears to provide that (1) so long as White Bluff Units 1 and 2 comply with modified or hybrid opacity standard of 20% opacity with one excused exceedance up to 27% per hour but no more than ten (10) such excused exceedances per day, then the units do not have to comply with the SIP opacity limit and (2) any violations of this modified or hybrid opacity limit are allowed -- i.e, completely excused -- if (3) those exceedances are the "direct result of unavoidable upset conditions in the nature of the process, or unavoidable and unforeseeable breakdown of any air pollution control equipment or related operating equipment, or as a direct result of shutdown or start-up of the operating unit," (4) so long as another series of conditions are met.[7]

This approach is unlawful for a number of reasons. The most basic is that it does not identify the Arkansas SIP's opacity as an applicable requirement that is independently applicable and federally enforceable requirement for Units 1 and 2. Because the hybrid opacity limit does not assure full compliance with all the requirements of both the NSPS Subpart D opacity limit and the Arkansas SIP opacity limit, the Draft White Bluff Permit is unlawful.

The only conceivable explanation for creating the modified NSPS Subpart D opacity limit in place of the Arkansas SIP opacity limit was to "streamline" the two applicable opacity limitations applicable to Units 1 and 2 into a single set of requirements. In certain circumstances not present here, EPA has allowed such streamlining. *See generally* 3/5/95 EPA White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program from Lydia N. Wegman, Deputy Director, Office of Air Quality Planning and Standards to Director, Office of Ecosystem Protection, Region I *et al*. ("White Paper 2") at 2, pdf 7 through 16, pdf 21 (providing guidance on proper procedures for streamlining Title V permit requirements). For streamlining to be appropriate and lawful, the streamlined limit must still "assure compliance with ***all applicable requirements***." *Id.* at Cover Memo at 2, pdf 2 (emphasis added); at White Paper at 11, n. 9, pdf 16 ("Title V allows for the establishment of a streamlined requirement, provided that it assures compliance with all applicable requirements it subsumes."). There are two ways that this can be accomplished, either by allowing a permit to specify compliance with a clearly more stringent limit or "[i]f no one requirement is unambiguously more stringent than the others," by allowing for the creation of a hybrid permit provision in a Title V permit which synthesizes multiple

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discretion would be exercised into an absolute legal exemption. And, in the case of the emergency provision, instead of being couched as an absolute affirmative defense to be asserted (or waived) and proven by a defendant, the provision has been converted into a legal exemption or exclusion from liability in the first instance.

[7] Even if an absolute exception was subject to ADEQ's director's discretion, the legal arguments set forth below remain fully applicable and, because the permit allows for the same violations to be absolutely exempted, this provision remains unlawful for all the reasons set forth herein.

applicable requirements into one limit that ensures compliance with all aspects of all applicable requirements. *Id.* at White Paper at 2, pdf 7, at 8-9, pdf 13-14 (providing guidance on proper procedures for demonstrating equivalent stringency Title V permit requirements), at 11-12, pdf 16-17 (providing guidance for situations "where it is difficult to determine a single most stringent applicable emissions limit by comparing all the applicable emissions limits with each other" and discussion option of creating an alternative hybrid limit"), at 13-16, pdf 18-21 (process for assessing stringency and establishing limit). The hybrid opacity limit at Condition 28 of the Draft White Bluff Permit does neither.

The hybrid opacity limit in Specific Condition 28 of the Draft White Bluff Permit does not impose equal or more stringent opacity requirements on White Bluff Units 1 and 2 than the Arkansas SIP opacity limit at APCEC Reg. 19.503(B)(1).[8] The Arkansas SIP opacity limit is not subject to an absolute exemption for startups and shutdowns while the hybrid opacity limit does allow exceedances of that limit to be excused where they are a direct result of a startup and shutdown. Draft White Bluff Permit, Condition 28 at pdf 26 ("Violations of this condition may be allowed . . . as a direct result of shutdown or start-up of the operating unit ...."). Under the hybrid opacity limit, an unlimited number of opacity exceedances resulting from startups and shutdowns are excused which would otherwise violate the Arkansas SIP limit,[9] and the magnitude of those opacity exceedances are not limited in any manner, meaning that each one could potentially be 100% opacity.[10] And startups and shutdowns can last for many hours or theoretically even days in certain circumstances. *See generally* 8/27/07 Entergy Emergency Shutdown Report to ADEQ at 1 (reflecting 6-hr. startup); Entergy Opacity Exceedance Report for 7/01/07 - 9/30/07 at 1 (*e.g.*, showing opacity exceedances at White Bluff Unit 2 of 100%, 90%, 79.8%, 78.2%, and 68.8% on 7/7/07

[8] No demonstration appears to have been set forth publicly that attempts to show that either the standard NSPS Subpart D opacity limit or the hybrid opacity limit in Specific Condition 28 was equally as stringent as the Arkansas SIP's opacity limit. Without such a demonstration, it was unlawful and remains unlawful to have effectively replaced the Arkansas SIP opacity limit with the hybrid opacity limit in Specific Condition 28.

[9] The Arkansas SIP opacity limit is subject to the Arkansas SIP's upset conditions provision, APCEC Reg. 19.601, but that in no excuses any opacity violation. Instead, it merely provides assurances about how ADEQ will exercise is enforcement discretion when upsets, including startups and shutdowns occur. And although the emergency condition provision at APCEC Reg. 19.602 is applicable to Arkansas SIP opacity exceedances and provides an affirmative defense if all applicable conditions are satisfied, similar (but different conditions) are largely covered in the hybrid opacity limit so that there would appear to be little difference between the two provisions in that one respect.

[10] In certain situations, emissions of opacity from such large boilers at 100% could potentially be associated with PM emissions that might even threaten to cause PM NAAQS violations. This is another reason that PM2.5 modeling must be conducted prior to the issuance of this permit.

and 7/8/07). For these reasons, the hybrid opacity limit at Specific Condition 28 is substantially less stringent than the Arkansas SIP opacity limit. *See* 3/1/05 Entergy's Comments on White Bluff's Final Air Permit (0263-AOP-R3) at 2 (Entergy admits as much by adamantly contending that the state law only opacity standard found at APCEC Reg. 18.501, which is identical the Arkansas SIP opacity limit in terms of exclusions/exemptions and the magnitude of opacity emissions allowed, is more stringent than the NSPS Subpart D opacity limit).

In addition, the hybrid opacity limit is also less stringent than the Arkansas SIP's opacity limit because the Arkansas SIP opacity limit only allows for deviations above 20% opacity (up to 60% opacity) no more than once in any consecutive 60-minute period and only three (3) times per 24-hour period, while the hybrid opacity limit allows up to ten (10) exceedances of the 20% limit per day (up to 27% opacity). Thus, seven (7) more opacity exceedances are allowed under the hybrid opacity limit.

Finally, the time frames over which excused exceedances are evaluated also make the hybrid opacity limit less stringent that the Arkansas SIP opacity limit. The hybrid opacity limit allows an opacity excursion once ***per hour*** up to 27% opacity and but no more than ten (10) such excused opacity exceedances ***per day*** are allowed. The Arkansas SIP's opacity limit allows an opacity excursion once ***in any consecutive 60-minute period*** up to 60% opacity but no more than three (3) such excused opacity exceedances ***per 24-hour period*** are allowed. Because of these differences, it is possible that what would otherwise be a violation of the Arkansas SIP's opacity limit would be excused under the hybrid opacity limit in Specific Condition 28 of the Draft White Bluff Permit Title V Renewal Permit.

For example, if two opacity exceedances which both averaged 25% opacity occurred within one 60-minute consecutive period but in different hours, one of them would constitute a violation of the Arkansas SIP's opacity limit but both would be exempt under the hybrid opacity limit's once per hour exemption. Similarly, if four opacity exceedances which each averaged 25% opacity and otherwise fell within the once per hour up to 60% opacity exemption of the Alabama SIP opacity limit occurred within a consecutive 24 hour period but half occurred on one day and the half occurred on another, one of those violations would constitute a violation of the Alabama SIP's opacity limit. However, under the hybrid opacity limit, all four opacity exceedances would be excused. This is another illustration of how the hybrid opacity limit is less stringent that the Arkansas SIP's limit.

As explained above, the Draft White Bluff Permit fails to adequately set forth all applicable requirements relating to opacity or to identify a set of opacity requirements that are other adequate to lawfully ensure compliance with all applicable opacity requirements. For this reason, the Draft White Bluff Permit is technically inadequate and unlawful as written.

Thank you for considering these comments.

Sincerely,

William J. Moore, III

Exhibits Enclosed:
cc: Mike Bates, ADEQ Air Division Manager
Charles Hurt, P.E., ADEQ Engineer

EXHIBIT LIST

1. Dr. Ranajit Sahu's Preliminary Report

2. AERMOD Modeling of SO2 Impacts of the Entergy White Bluff Coal Plant, prepared for Sierra Club by Khanh T. Tran, AMI

3. 1/20/05 E-mail from ADEQ's A. Sudmeyer to Entergy's G. Johnson

4. 3/5/95 EPA White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program from Lydia N. Wegman, Deputy Director, Office of Air Quality Planning and Standards to Director, Office of Ecosystem Protection, Region I *et al*.

5. 8/27/07 Entergy Emergency Shutdown Report to ADEQ

6. Entergy Opacity Exceedance Report for 7/01/07 - 9/30/07

SIERRA CLUB
FOUNDED 1892

Via electronic mail and hand delivery August 14, 2014

Teresa Marks, Director
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, Arkansas 72118-5317
Attention: ADEQ Air Permits Branch
airpermits@adeq.state.ar.us

Re: ***Supplemental Comments of the Sierra Club on the Proposed Modification to the Title V Operating Permit for Entergy-Arkansas, Inc.'s White Bluff Plant, Draft Operating Air Permit (Permit No.: 0263-AOP-R8)***

Dear Ms. Marks:

I submit these supplemental comments on behalf of the Sierra Club on the proposed modification to the Title V Operating Permit for Entergy-Arkansas, Inc.'s ("Entergy") White Bluff Plant (Permit No.: 0263-AOP-R8) (hereinafter "Draft White Bluff Permit"). For the reasons expressed here and in Sierra Club's comments submitted to the Arkansas Department of Environmental Quality ("ADEQ") on July 11, 2014, the Draft White Bluff Permit should not be issued as proposed as it fails to adequately protect air quality in Arkansas.

Sierra Club is the nation's oldest environmental organization. It has more than 2.4 million members and supporters nationwide and is dedicated to the protection and preservation of the natural and human environment. Among other environmental concerns, Sierra Club is focused on addressing the pressing environmental and health problems associated with the mining, burning, and disposal of coal and its combustion by-products.

In Arkansas, Sierra Club has thousands of members, many of whom are negatively affected by air emissions from the White Bluff Plant. Sierra Club and its many impacted members are "interested persons" in regard to this proposed permitting action. Sierra Club members in Arkansas (and elsewhere) have a strong interest in ensuring that the White Bluff Plant fully complies with the applicable air quality regulations and that both Entergy and ADEQ strictly adhere to Arkansas's substantive and procedural rules governing modifications to air operating permits.

Sierra Club submits these supplemental comments because we had not received responses to relevant public record requests in time to evaluate the requested documents ahead of the close of the July 11, 2014 comment period. Sierra Club appreciates ADEQ's prompt response to those requests and this opportunity to submit supplemental comments on the Draft White Bluff Permit at this public hearing.[1]

I. The Draft White Bluff Permit Cannot Lawfully Be Issued Because No Adequate Determination Has Been Made that the Modified White Bluff Plant Will Not Violate a NAAQS.

As demonstrated in Sierra Club's July 11, 2014 comments, the proposed activated carbon injection ("ACI") project covered by the Draft White Bluff Permit is likely to result in an increase in PM emissions of over 22 tons per year. *See* Sierra Club July 11, 2014 Comments at 2-3. This increase in PM emissions will damage the health of Arkansans and violate the federally enforceable Arkansas State Implementation Plan ("SIP"). Under the Arkansas SIP, without a determination by ADEQ that the modified White Bluff Plant will not cause a violation of a NAAQS (or any other applicable emissions limitation), the Draft White Bluff Permit cannot lawfully be issued. ADEQ has made no such determination.

Under the Arkansas SIP, no permit for the modification of equipment may be issued where the modification causes a violation of any NAAQS:

> No person shall cause or permit the construction or modification of equipment which would cause or allow the following standards or limitations which are in effect as of the effective date of this regulation, to be exceeded:
>
> > (A) Any National Ambient Air Quality Standard or ambient air increment (as listed in 40 CFR 52.21).
> > (B) Any applicable emission limitation promulgated by the United States Environmental Protection Agency.
> > (C) Any applicable emission limitation promulgated by the Department in this regulation.

APC&E Reg. 19.502, General Regulations.

The equipment modifications that Entergy has proposed for the White Bluff Plant constitute "modification of equipment" within the meaning of APC&E Regulation 19.502. The Draft White Bluff Permit states: "Compliance with MATS will result in the installation of additional emissions controls on each of the Unit 1 and Unit 2." Draft White Bluff Permit at 5. The "installation of additional emissions controls" constitutes "modification of equipment" under the plain meaning of APC&E Regulation 19. ADEQ, therefore, has a duty under the Arkansas SIP to ensure that no violation of an applicable NAAQS results from the operation of the modified White Bluff Plant before any permit may be issued.[2]

Despite these facts, neither ADEQ nor anyone else has performed any air modeling analysis or other comparable demonstration to show that the White Bluff Plant and the proposed

[1] These comments are submitted at the public hearing for this proposed permit modification. An electronic copy of these comments is provided for convenience.
[2] The Draft White Bluff Permit (at 6) confirms that APC&E Regulation 19 applies here.

modification project covered by the Draft White Bluff Permit will not interfere with attainment of the NAAQS. In fact, in its Statement of Basis for this permit, ADEQ concedes that no air dispersion modeling was performed and that "criteria pollutants were not evaluated for impacts on the NAAQS." Statement of Basis at 3. In the absence of such an analysis, the Draft White Bluff Permit cannot be lawfully issued.[3]

II. The Draft White Bluff Permit Cannot Lawfully Be Issued Because the Modified White Bluff Plant Will Violate Applicable Requirements of Arkansas Law that Protect Public Health.

As discussed above, the proposed ACI project covered by the Draft White Bluff Permit is likely to result in an increase in PM emissions of over 22 tons per year. This increase in PM emissions will damage the health of Arkansans and violate Arkansas anti-pollution laws. Without a determination by ADEQ that the modified White Bluff Plant will not cause harmful air pollution, the Draft White Bluff Permit cannot lawfully be issued. ADEQ has made no such determination.

The Arkansas legislature has declared the public policy of the state is "to maintain [] a reasonable degree of purity of the air resources of the state to the end that the least possible injury should be done to human, plant, or animal life." Ark. Code. § 8-4-301. ADEQ is of course charged with furthering this important state policy goal.

Arkansas law defines "air pollution" as "the presence in the outdoor atmosphere of one or more air contaminants in quantities, of characteristics, and of a duration that are materially injurious or can be reasonably expected to become materially injurious to human, plant, or animal life or to property . . . ." Ark. Code. § 8-4-303. It is unlawful under Arkansas's Water and Air Pollution Control Act to knowingly cause "air pollution." Ark. Code. § 8-4-310.

Before it can issue the Draft White Bluff Permit, ADEQ has a duty to ensure that the facility will not cause "air pollution," as defined under Arkansas law. Specifically, APC&E regulations provide that:

> No permit shall be granted or modified under this chapter unless the owner/operator demonstrates to the reasonable satisfaction of the Department that the stationary source will be constructed or modified to operate without resulting in a violation of applicable portions of this regulation *and without causing air pollution*.

APC&E Reg. 18.302, Approval Criteria (emphasis added).[4]

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[3] Sierra Club understands that in April 2013, the Arkansas government enacted a new law, Act 1302, that prohibits ADEQ from requiring a permit applicant to submit air quality modeling to demonstrate compliance with the NAAQS, and prohibits ADEQ from undertaking its own modeling or even considering modeling submitted by a third-party without the applicant's consent. This law does not override applicable regulations of the Arkansas SIP.

[4] The Draft White Bluff Permit (at 6) confirms that APC&E Regulation 18 applies here.

As demonstrated in Sierra Club's July 11, 2014 comments, Entergy's claim that PM emissions will decrease based on its proposed modifications is entirely unreliable. In fact, PM emissions are likely to substantially increase. There is accordingly no demonstration in the record that ADEQ may rely on to show that the modified White Bluff Plant will not cause "air pollution" as defined by Arkansas law. ADEQ is of course well-aware that exposure to PM emissions causes serious public health harms such as: effects on breathing and respiratory systems, chronic lung disease, damage to lung tissue, cancer, and premature death.[5] In the absence of a showing that such harms will not occur, the Draft White Bluff Permit cannot lawfully be issued.

III. Entergy's Emissions Estimates are Unreliable and Unverifiable.

The analysis Entergy performed to predict emissions from the modified White Bluff plant is almost entirely unreviewable and unverifiable because of a failure to provide necessary inputs and assumptions. As Dr. Sahu explains ADEQ has no basis to rely on Entergy's emissions estimates:

> In any analysis provided in a regulatory context, it is critically important that the entity performing the analysis provide all inputs and assumptions used so that the regulatory agency and others may assess the reliability and accuracy of the analysis. The New Source Review (NSR) analysis provided by Entergy to support the ACI project fails to meet this standard. Its work is almost entirely unreviewable and unverifiable because of a failure to provide support for the necessary inputs and assumptions or, in some cases, the inputs and assumptions themselves.

Supplement Report of Dr. Ranajit Sahu at 1 (Exhibit 1).

In his preliminary report that Sierra Club attached to its July 11, 2014 comments on the Draft White Bluff Permit, Dr. Sahu noted five critical flaws in Entergy's technical support for its claimed reduction in PM emissions from the ACI project:

- First, Entergy provides no details on the basic design parameters of the electrostatic precipitators ("ESPs") at White Bluff Units 1 and 2. This information is critical to any review regarding the performance of the ESPs with ACI addition at the White Bluff Plant. Sahu Preliminary Report at 1-2.[6]
- Second, Entergy does not state how much ACI (or which type) will be used in order to reduce mercury emissions to below the Mercury and Air Toxics Standards ("MATS") levels. In fact, no mercury testing data is provided at all. Thus, there is no data to show that a specific ACI process would lead to the necessary mercury reductions. Obviously, ACI runs that do not achieve the MATS-required mercury reductions are useless for assessing PM emissions since Entergy must comply with the MATS requirements for mercury. Sahu Preliminary Report at 2.
- Third, the June 2012 tests on Unit 1 are unreliable because the gas flow rates indicate that Unit 1 was running at a much reduced capacity during these tests thereby invalidating the

[5] *See* http://www.epa.gov/airtrends/aqtrnd95/pm10.html
[6] Sierra Club attached Dr. Sahu's preliminary report as Exhibit 1 to its July 11, 2014 comments.

tests' usefulness to predict emissions at full capacity. In addition, Unit 2 operates at much higher heat input rates than Unit 1 and thus Entergy's attempt to extrapolate results from Unit 1 to Unit 2 is not reasonable. Sahu Preliminary Report at 2

- Fourth, Entergy's failure to reasonably determine baseline PM emissions undermines its prediction of an emissions decrease. The identified wide range of possible PM baselines indicates that PM emission could increase, even under Entergy's flawed analysis. Sahu Preliminary Report at 3.
- Fifth, the Energy & Environmental Research Center tests provided by Entergy are not reliable because they were performed at an entirely different ESP, with different design parameters, and with no showing that these results could be achieved at the White Bluff ESPs. Sahu Preliminary Report at 3-6.

In his supplemental report attached to these comments, Dr. Sahu notes two additional flaws in Entergy's analysis:

- First, Entergy has not provided the inputs and assumptions used in the Aurora model that the company used to estimate projected futures estimates of emissions of all relevant pollutants. Entergy used this model to create projected heat input figures for Units 1 and 2. These heat input figures were then used by Entergy for all of its future emissions calculations. Without the inputs and assumptions used to generate the heat input figures, the emissions calculations themselves are not verifiable or even understandable. Sahu Supplemental Report at 1.
- Second, for a given future year, Entergy has adjusted (by roughly 5%) the Aurora projected heat input estimate to account for a "discrepancy" between how Entergy reports heat input to the U.S. EPA Clean Air Markets Division versus what Entergy believes the "accurate" heat input figure should be. In any case, in order to make this adjustment, Entergy states that it derived purportedly more accurate heat input numbers from fuel usage at each White Bluff unit and the heating value of the fuel(s). But Entergy provides only its final heat input values without any data to support the fuel usage and heating value inputs. Nor does Entergy provide any discussion as to why the heat input calculated from these parameters would be more accurate than the figures reported to the U.S. EPA. Sahu Preliminary Report at 1-2.

For all of these reasons, ADEQ has no reasonable basis for which to rely on Entergy's emissions estimates. There is therefore no demonstration in the permitting record that the modified White Bluff Plant will not violate federal or Arkansas air quality requirements. Without such an analysis, ADEQ cannot lawfully issue the modified White Bluff permit.

Thank you for considering these comments.

Sincerely,

/s/ Tony G. Mendoza

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Exhibit Enclosed.

<u>Preliminary Statement to the Arkansas Department of Environmental Quality</u>

<u>on White Bluff Draft Permit No.: 0263-AOP-R8</u>

<u>by</u>

<u>Dr. Ranajit (Ron) Sahu, Consultant</u>

1. Sierra Club has asked me to review the assertions made by Entergy Arkansas that the addition of activated carbon injection (ACI) combined with halide coal pretreatment will reduce the particulate matter (PM) emissions from the plant's two primary stacks. I have over 15 years of experience evaluating the operation of coal plant pollution control operations. Specifically, I have over five years of experience dealing with the application of sorbent technologies such as ACI to reduce mercury emissions, and their resulting impacts on particulate controls such as electrostatic precipitators **(**ESPs).

My CV is enclosed with this statement in Attachment A.

Sierra Club continues to seek information from the Arkansas Department of Environmental Quality concerning the operations of the White Bluff Plant, so these are preliminary comments.

2. In its Notice of Intent to Construct and its June 2013 Permit Application, Entergy claims that the addition of ACI (in either brominated or non-brominated form) will improve ESP efficiency by reducing the resistivity of the fly ash (see December 17, 2012 Letter from Entergy to ADEQ re: Notice of Intent to Construct). However, this claim is not supported by the evidence that Entergy has submitted, as many critical details are missing. In simple terms, Entergy provides two pieces of evidence that addition of ACI will improve ESP efficiency and therefore reduce PM emissions. Neither line of evidence is properly supported and both lines of evidence have fatal flaws.

3. But, before critiquing these lines of evidence, the most basic information on the actual ESPs at each unit is missing in the record:

(a) The application and draft permit contain no details on even the basic design parameters of the ESPs at Units 1 and 2. For example, there is no mention or discussion of the number of parallel gas paths; the number of fields; the number of transfomer/rectifier sets; the Specific Collection Area; the average gas velocity; the average residence time; the electrical operating conditions (including primary/secondary voltage and currents, spark rates, etc.) or any other design parameter for either ESP. The actual removal efficiency of the ESP will depend on these and other variables. Thus, none of the test data provided in support of Entergy's position can be evaluated. It is also clear that the ADEQ could not have evaluated Entergy's claim regarding the performance of the ESPs with ACI addition.

(b) The application and draft permit contain no details on the state of maintenance of each ESP, including maldistribution of gas flows, or the degree to which specific sections of each ESP may be impaired due to broken charging wires, rappers, etc. Actual conditions will dictate actual removal efficiencies.

4. In addition, the application does not state exactly how much ACI (or which type) will be used in order to reduce mercury emissions to below the MATS levels. In fact, the record does not contain any mercury test data, so even if a specific ACI rate is provided there is no ability to determine if this level of ACI usage will provide the requisite mercury reduction.

5. First Line of Evidence: June 2012 Tests on Unit 1.

The following issues are noted:

(a) Two levels of ACI were apparently used – simply noted as "Long Term 1" and "Long Term 2." But there is no discussion of what these terms mean. There is no discussion of the type (other than noting it was brominated) or quantity of ACI used in the Long Term 1 and 2 tests. This alone makes the tests unreliable and useless. Also, since non-brominated or normal ACI was not used (which would require higher levels of ACI injection for the same level of mercury removal), the test data and conclusions cannot be used for non-brominated ACI injection conditions – which Entergy states is a possibility.[1]

(b) ESP control efficiency was not measured during either the "baseline" or the two ACI tests (i.e., via measurement of inlet and outlet filterable particulate[2] concentrations). Thus, any claim that the efficiency will improve at the actual ESPs is simply unsupported via actual testing at the units themselves.

(c) No tests were done at Unit 2. Yet, the record shows that Unit 2 often operates at much higher heat input rates (and therefore higher coal/ash loading rates) than Unit 1. Thus, Entergy improperly seeks to extrapolate results from Unit 1 testing (even if done correctly, which it was not) to Unit 2. There is no reason to expect that the efficiencies of each ESP, even under comparable conditions, will be similar.

(d) The exhaust gas flow rates during all of the June 2012 tests (baseline, and ACI runs) – around 1.4-1.5 million acfm – were approximately half of the flow rates recorded for all of the other tests done at Unit 1 that I have reviewed (i.e., in April 2010 and in October of 2012) – which are typically over 3.1 million acfm. This strongly suggests that Unit 1 was running at a much reduced capacity during these June 2012 tests (with consequent low particulate loading to the ESP as compared to normal, full load conditions) – thereby completely invalidating their usefulness to full load or design conditions. It is not clear why the conditions of the test were

[1] Entergy states in the Draft –R8 permit, Section II that "The primary emission control unit will be an activated carbon injection (ACI) system. The ACI system will use either brominated activated carbon or non-halogenated activated carbon that is injected post combustion. If non-brominated activated carbon is used by the ACI then a separate halide solution would be applied to the coal prior to combustion."

[2] In all instances that I use the word particulate, it means PM_{10}.

designed to be so unrepresentative of unit operating conditions. This is a fatal flaw unless Entergy can explain how and why the flow rates for Unit 1 were so dramatically lower than any other tests at Unit 1.

(e) Entergy's conclusion that the addition of brominated ACI results in a meaningful decrease in PM emissions requires reliable data about what baseline emissions (those without ACI) actually are. However, filterable particulate data from all of the available tests (i.e., including those in 2010 as well as later October 2012 and December 2013 tests) show that filterable particulate levels varied considerably, as follows:

April 2010 Unit 1:	0.008 – 0.038 lb/MMBtu
April 2010 Unit 2:	0.010 – 0.022 lb/MMBtu
June 2012 Unit 1 :	0.016 – 0.021 lb/MMBtu
October 2012 Unit 1:	0.028 – 0.055 lb/MMBtu

Thus, the range of filterable PM emissions from the baseline (i.e., non-ACI) White Bluff units ranged from **0.008 – 0.055 lb/MMBtu** (a factor of almost 7) just based on the available tests so far.

(f) The only ACI tests (i.e, during June 2012 at Unit 1) showed the following filterable PM emissions range:

June 2012 Unit 1:	**0.012-0.015 lb/MMBtu**

Clearly, this range of emissions with ACI is well within the range of filterable PM during baseline, non-ACI conditions, which included tests at 0.008 lb/MMBtu and 0.010 lb/MMBtu. Thus, the available data do not support that filterable PM emissions will decrease when ACI is added. In fact, the collective test data can also be interpreted as showing a plausible increase in filterable particulate emissions when ACI is added.

Of course, I reiterate that the June 2012 tests may be fatally compromised anyway due to the unrepresentative flow conditions and the total lack of documentation of ACI injection rates actually used. In summary, the reliance on the June 2012 tests by Entergy to support its position that filterable PM emissions will decrease with ACI addition is simply improper.

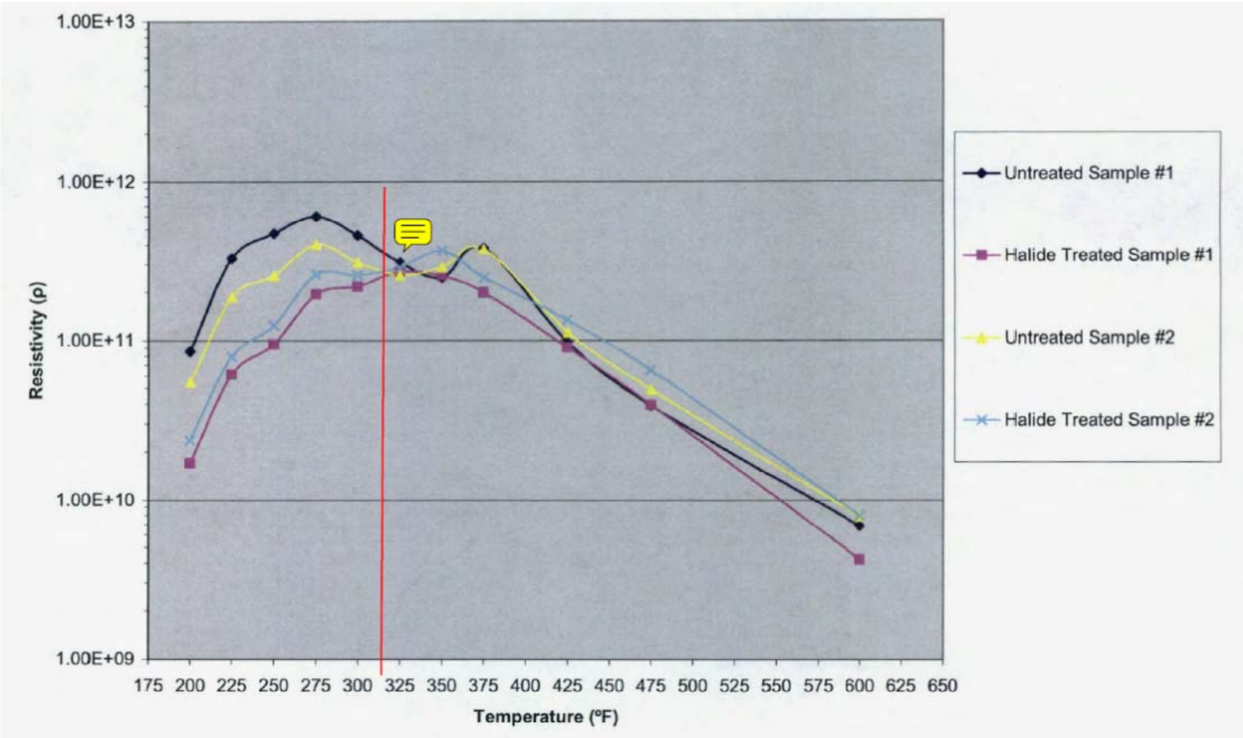
6. Second Line of Evidence: The EERC Tests.

In Appendix B to its December 2012 letter to ADEQ, Entergy provides some data from testing conducted at the Energy and Environmental Research Center (EERC) with, supposedly, ash from White Bluff. No relevant conclusions can be drawn from the data presented.

(a) First, it is not clear what coal ash was sent to EERC since footnote 1 to Table 1 states that the coal additive included 0.25% S-Sorb for NOx control. It is not clear why this additive was used or how it may have affected the results since it is not proposed for use by Entergy in its -08 application.

(b) Entergy claims that its ESPs (i.e., at Units 1 and 2) have efficiencies of 99.955% (baseline) and 99.962% (with ACI), based on tests conducted at EERC. But, ESP efficiency is not just a property of coal ash content. It is more importantly, a function of ESP design and operating conditions (such as those discussed earlier). It is completely meaningless to therefore assume that the efficiencies obtained by EERC in its own, completedly different test ESP, are at all relevant to the actual ESPs at White Bluff. Thus, even if it were the case that the EERC test did observe an improvement in its ESP as a result of the ACI-added ash, it has no relevance for a similar conclusion at the plant. Thus, Entergy's claim that its own ESPs will have similar efficiencies is ludicrous.

(c) The EERC test shows a plot of the resistivity of two types of ash ("Untreated" or presumably baseline and "Halide Treated" presumably with ACI) as a function of temperature. It is shown below.



Actual gas temperatures at the ESPs are greater than 300° F as readily seen in the various stack test reports mentioned earlier. In fact, temperatures at the stack probe location are typically greater than 300° F – meaning that temperatures at the ESP would be even higher – likely in the 350° F range or so. As the EERC graph clearly shows, there is marginal, if any, difference between the untreated and treated samples between 300°-350° F. Arguably, the data can even support the finding that the treated samples have higher resistivity (see the second, blue-lined, treated sample) compared to the untreated (black and yellow lines) samples. In any case, the EERC data simply do not support a meaningful or material decrease in resistivity due to the "halide treatment" as claimed by Entergy.

Thus, this second line of evidence is also completely unreliable as.

7. In fact, a more reasonable assessment of the test data and the EERC data points to the following: (a) that resistivity changes as a result of adding ACI are not meaningful at the relevant temperatures; (b) the use of EERC ESP efficiencies as being the same for the White Bluff ESPs is bogus and nonsensical; (c) the June 2012 tests, notwithstanding their unrepresentativeness, show no meaningful reduction in filterable PM levels as a result of ACI addition.

8. What is clear is that with ACI addition, the particulate loading into the ESPs will increase. The Road Emission Calculations spreadsheet provided by Entergy states that the maximum annual ACI Injection Rate (or usage) will be 2,278 tons/year for both units. Assuming an ESP filterable PM efficiency of 99% (which is generous, given the total lack of information on ESP design, condition, and operating parameters) for each ESP, the incremental emissions of filterable PM as a result of the additional ACI loading is approximately 2,278*(1-0.99) = 22.8 tons/year. In addition, as Entergy notes, there are additional increases in fugitive PM emissions as a result of road traffic, ash hauling, ACI transport, etc. Collectively, the expected increase in filterable PM emissions, therefore, is likely above 22.8 tons/year. This exceeds the PSD Significant Emissions Rate for PM_{10}, which is 15 tons/year.[3] Thus, it is more likely than not that the addition of ACI, as proposed by Entergy for White Bluff Units 1 and 2, will trigger PSD review for this pollutant. This means that the application and permit are incomplete, since Entergy has not provided a BACT analysis, or any ambient air quality modeling analysis, or any of the other PSD application requirements (such as impacts to Air Quality Related Values), *etc*.

9. The draft permit R-08 contains no conditions limiting ACI usage. Although the validity of Entergy's testing is highly questionable, if ADEQ accepts it as sufficient to demonstrate that PM emissions will not increase, then the permit must contain parameters ensuring that plant operation will mirror the fundamental conditions of the ACI tests conducted. Yet the draft permit contains no conditions specifying the type or amount of ACI that must be used. Thus, there is no enforceability related to PM increases discussed above.

10. The draft permit R-08 contains no conditions that require testing of the White Bluff ESP efficiencies. Since Entergy has relied on ESP efficiency data (erroneously, as discussed above) to claim improvement, it should directly verify, via enforceable permit condition(s), what the actual ESP efficiencies are for White Bluff Units 1 and 2.

11. The draft R-08 permit states that the two White Bluff units have heat inputs of 8,700 MMBtu/hr (see page 16). Contradicting this, the formula in Condition 26 implies that the

[3] 40 C.F.R. § 52.21(b)(23)(i)

maximum hourly heat input rate for each unit is 8,950 MMBtu/hr. This value is also noted as the "Unit Nominal Max Heat Input" in the NSR Evaluation Spreadsheets (dated 11-07-13) for each unit. Yet, a simple review of just the 2013 hourly heat inputs reported to the EPA as part of its Acid Gas reporting requirements, shows that each unit exceeded the 8,950 MMBtu/hr and the 8,700 MMBtu/hr values for thousands of hours. Thus, none of the supposed New Source Review (NSR)/PSD calculations which rely on the 8,950 MMBtu/hr value are reliable.

12. The PSD evaluations also seem to rely, fundamentally, on future year (i.e., 2015 to 2020) heat input projections from the Aurora model (see the tab "Heat Input Adjustment") in each units NSR evaluation spreadsheet. Yet, no details of the various assumptions and inputs for the Aurora model are provided. Thus, these projections of future year heat inputs cannot be verified nor supported, thus invalidating the so-called PSD analyses presented by Entergy.

13. As noted above, these results are preliminary as Sierra Club is seeking additional information from ADEQ concerning this application. However, based on the publicly available information, it is my conclusion at this time that ADEQ cannot rely upon Entergy's unsupported assertion that PM emissions will decrease as a result of the addition of ACI.

(Ranajit Sahu)

ATTACHMENT A - RESUME

RANAJIT (RON) SAHU, Ph.D, QEP, CEM (Nevada)

CONSULTANT, ENVIRONMENTAL AND ENERGY ISSUES

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EXPERIENCE SUMMARY

Dr. Sahu has over twenty three years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment for a wide range of emissions sources; soils and groundwater remediation including landfills as remedy; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

Specifically, over the last 20+ years, Dr. Sahu has consulted on several municipal landfill related projects addressing landfill gas generation, landfill gas collection, and the treatment/disposal/control of such gases in combustion equipment such as engines, turbines, and flares. In particular, Dr. Sahu has executed numerous projects relating to flare emissions from sources such as landfills as well as refineries and chemical plants. He has served as a peer-reviewer for EPA in relation to flare combustion efficiency, flare destruction efficiency, and flaring emissions.

He has over twenty one years of project management experience and has successfully managed and executed numerous projects in this time period. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public. Notably, he has successfully managed a complex soils and groundwater remediation project with a value of over $140 million involving soils characterization, development and implementation of the remediation strategy including construction of a CAMU/landfill and associated groundwater monitoring, regulatory and public interactions and other challenges.

He has provided consulting services to numerous private sector, public sector and public interest group clients. His major clients over the past twenty three years include various steel mills, petroleum refineries, cement companies, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, and various entities in the public sector including EPA, the US Dept. of Justice, California DTSC, various municipalities, etc.). Dr. Sahu has performed projects in over 44 states, numerous local jurisdictions and internationally.

In addition to consulting, Dr. Sahu has taught numerous courses in several Southern California universities including UCLA (air pollution), UC Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management) for the past seventeen years. In this time period he has also taught at Caltech, his alma mater (various engineering courses), at the University of Southern California (air pollution controls) and at California State University, Fullerton (transportation and air quality).

Dr. Sahu has and continues to provide expert witness services in a number of environmental areas discussed above in both state and Federal courts as well as before administrative bodies (please see Annex A).

EXPERIENCE RECORD

2000-present **Independent Consultant.** Providing a variety of private sector (industrial companies, land development companies, law firms, etc.) public sector (such as the US Department of Justice) and public interest group clients with project management, air quality consulting, waste remediation and management consulting, as well as regulatory and engineering support consulting services.

1995-2000 Parsons ES, **Associate, Senior Project Manager and Department Manager for** Air Quality/Geosciences/Hazardous Waste Groups, Pasadena. Responsible for the management of a group of approximately 24 air quality and environmental professionals, 15 geoscience, and 10 hazardous waste professionals providing full-service consulting, project management, regulatory compliance and A/E design assistance in all areas.

Parsons ES, **Manager for Air Source Testing Services**. Responsible for the management of 8 individuals in the area of air source testing and air regulatory permitting projects located in Bakersfield, California.

1992-1995 Engineering-Science, Inc. **Principal Engineer and Senior Project Manager** in the air quality department. Responsibilities included multimedia regulatory compliance and permitting (including hazardous and nuclear materials), air pollution engineering (emissions from stationary and mobile sources, control of criteria and air toxics, dispersion modeling, risk assessment, visibility analysis, odor analysis), supervisory functions and project management.

1990-1992 Engineering-Science, Inc. **Principal Engineer and Project Manager** in the air quality department. Responsibilities included permitting, tracking regulatory issues, technical analysis, and supervisory functions on numerous air, water, and hazardous waste projects. Responsibilities also include client and agency interfacing, project cost and schedule control, and reporting to internal and external upper management regarding project status.

1989-1990 Kinetics Technology International, Corp. **Development Engineer.** Involved in thermal engineering R&D and project work related to low-NOx ceramic radiant burners, fired heater NOx reduction, SCR design, and fired heater retrofitting.

1988-1989 Heat Transfer Research, Inc. **Research Engineer**. Involved in the design of fired heaters, heat exchangers, air coolers, and other non-fired equipment. Also did research in the area of heat exchanger tube vibrations.

EDUCATION

1984-1988 Ph.D., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.

1984 M. S., Mechanical Engineering, Caltech, Pasadena, CA.

1978-1983 B. Tech (Honors), Mechanical Engineering, Indian Institute of Technology (IIT) Kharagpur, India

TEACHING EXPERIENCE

Caltech

"Thermodynamics," Teaching Assistant, California Institute of Technology, 1983, 1987.

"Air Pollution Control," Teaching Assistant, California Institute of Technology, 1985.

"Caltech Secondary and High School Saturday Program," - taught various mathematics (algebra through calculus) and science (physics and chemistry) courses to high school students, 1983-1989.

"Heat Transfer," - taught this course in the Fall and Winter terms of 1994-1995 in the Division of Engineering and Applied Science.

“Thermodynamics and Heat Transfer,” Fall and Winter Terms of 1996-1997.

U.C. Riverside, Extension

"Toxic and Hazardous Air Contaminants," University of California Extension Program, Riverside, California. Various years since 1992.

"Prevention and Management of Accidental Air Emissions," University of California Extension Program, Riverside, California. Various years since 1992.

"Air Pollution Control Systems and Strategies," University of California Extension Program, Riverside, California, Summer 1992-93, Summer 1993-1994.

"Air Pollution Calculations," University of California Extension Program, Riverside, California, Fall 1993-94, Winter 1993-94, Fall 1994-95.

"Process Safety Management," University of California Extension Program, Riverside, California. Various years since 1992-2010.

"Process Safety Management," University of California Extension Program, Riverside, California, at SCAQMD, Spring 1993-94.

"Advanced Hazard Analysis - A Special Course for LEPCs," University of California Extension Program, Riverside, California, taught at San Diego, California, Spring 1993-1994.

“Advanced Hazardous Waste Management” University of California Extension Program, Riverside, California. 2005.

Loyola Marymount University

"Fundamentals of Air Pollution - Regulations, Controls and Engineering," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1993.

"Air Pollution Control," Loyola Marymount University, Dept. of Civil Engineering, Fall 1994.

“Environmental Risk Assessment,” Loyola Marymount University, Dept. of Civil Engineering. Various years since 1998.

“Hazardous Waste Remediation” Loyola Marymount University, Dept. of Civil Engineering. Various years since 2006.

University of Southern California

"Air Pollution Controls," University of Southern California, Dept. of Civil Engineering, Fall 1993, Fall 1994.

"Air Pollution Fundamentals," University of Southern California, Dept. of Civil Engineering, Winter 1994.

University of California, Los Angeles

"Air Pollution Fundamentals," University of California, Los Angeles, Dept. of Civil and Environmental Engineering, Spring 1994, Spring 1999, Spring 2000, Spring 2003, Spring 2006, Spring 2007, Spring 2008, Spring 2009.

International Programs

“Environmental Planning and Management,” 5 week program for visiting Chinese delegation, 1994.

“Environmental Planning and Management,” 1 day program for visiting Russian delegation, 1995.

“Air Pollution Planning and Management,” IEP, UCR, Spring 1996.

“Environmental Issues and Air Pollution,” IEP, UCR, October 1996.

PROFESSIONAL AFFILIATIONS AND HONORS

President of India Gold Medal, IIT Kharagpur, India, 1983.

Member of the Alternatives Assessment Committee of the Grand Canyon Visibility Transport Commission, established by the Clean Air Act Amendments of 1990, 1992-present.

American Society of Mechanical Engineers: Los Angeles Section Executive Committee, Heat Transfer Division, and Fuels and Combustion Technology Division, 1987-present.

Air and Waste Management Association, West Coast Section, 1989-present.

PROFESSIONAL CERTIFICATIONS

EIT, California (# XE088305), 1993.

REA I, California (#07438), 2000.

Certified Permitting Professional, South Coast AQMD (#C8320), since 1993.

QEP, Institute of Professional Environmental Practice, since 2000.

CEM, State of Nevada (#EM-1699). Expiration 10/07/2011.

PUBLICATIONS (PARTIAL LIST)

"Physical Properties and Oxidation Rates of Chars from Bituminous Coals," with Y.A. Levendis, R.C. Flagan and G.R. Gavalas, *Fuel*, **67**, 275-283 (1988).

"Char Combustion: Measurement and Analysis of Particle Temperature Histories," with R.C. Flagan, G.R. Gavalas and P.S. Northrop, *Comb. Sci. Tech.* **60**, 215-230 (1988).

"On the Combustion of Bituminous Coal Chars," PhD Thesis, California Institute of Technology (1988).

"Optical Pyrometry: A Powerful Tool for Coal Combustion Diagnostics," *J. Coal Quality*, **8**, 17-22 (1989).

"Post-Ignition Transients in the Combustion of Single Char Particles," with Y.A. Levendis, R.C.Flagan and G.R. Gavalas, *Fuel*, **68**, 849-855 (1989).

"A Model for Single Particle Combustion of Bituminous Coal Char." Proc. ASME National Heat Transfer Conference, Philadelphia, **HTD-Vol. 106**, 505-513 (1989).

"Discrete Simulation of Cenospheric Coal-Char Combustion," with R.C. Flagan and G.R.Gavalas, *Combust. Flame*, **77**, 337-346 (1989).

"Particle Measurements in Coal Combustion," with R.C. Flagan, in "**Combustion Measurements**" (ed. N. Chigier), Hemisphere Publishing Corp. (1991).

"Cross Linking in Pore Structures and Its Effect on Reactivity," with G.R. Gavalas in preparation.

"Natural Frequencies and Mode Shapes of Straight Tubes," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Optimal Tube Layouts for Kamui SL-Series Exchangers," with K. Ishihara, Proprietary Report for Kamui Company Limited, Tokyo, Japan (1990).

"HTRI Process Heater Conceptual Design," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Asymptotic Theory of Transonic Wind Tunnel Wall Interference," with N.D. Malmuth and others, Arnold Engineering Development Center, Air Force Systems Command, USAF (1990).

"Gas Radiation in a Fired Heater Convection Section," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1990).

"Heat Transfer and Pressure Drop in NTIW Heat Exchangers," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1991).

"NOx Control and Thermal Design," Thermal Engineering Tech Briefs, (1994).

"From Puchase of Landmark Environmental Insurance to Remediation: Case Study in Henderson, Nevada," with Robin E. Bain and Jill Quillin, presented at the AQMA Annual Meeting, Florida, 2001.

"The Jones Act Contribution to Global Warming, Acid Rain and Toxic Air Contaminants," with Charles W. Botsford, presented at the AQMA Annual Meeting, Florida, 2001.

PRESENTATIONS (PARTIAL LIST)

"Pore Structure and Combustion Kinetics - Interpretation of Single Particle Temperature-Time Histories," with P.S. Northrop, R.C. Flagan and G.R. Gavalas, presented at the AIChE Annual Meeting, New York (1987).

"Measurement of Temperature-Time Histories of Burning Single Coal Char Particles," with R.C. Flagan, presented at the American Flame Research Committee Fall International Symposium, Pittsburgh, (1988).

"Physical Characterization of a Cenospheric Coal Char Burned at High Temperatures," with R.C. Flagan and G.R. Gavalas, presented at the Fall Meeting of the Western States Section of the Combustion Institute, Laguna Beach, California (1988).

"Control of Nitrogen Oxide Emissions in Gas Fired Heaters - The Retrofit Experience," with G. P. Croce and R. Patel, presented at the International Conference on Environmental Control of Combustion Processes (Jointly sponsored by the American Flame Research Committee and the Japan Flame Research Committee), Honolulu, Hawaii (1991).

"Air Toxics - Past, Present and the Future," presented at the Joint AIChE/AAEE Breakfast Meeting at the AIChE 1991 Annual Meeting, Los Angeles, California, November 17-22 (1991).

"Air Toxics Emissions and Risk Impacts from Automobiles Using Reformulated Gasolines," presented at the Third Annual Current Issues in Air Toxics Conference, Sacramento, California, November 9-10 (1992).

"Air Toxics from Mobile Sources," presented at the Environmental Health Sciences (ESE) Seminar Series, UCLA, Los Angeles, California, November 12, (1992).

"Kilns, Ovens, and Dryers - Present and Future," presented at the Gas Company Air Quality Permit Assistance Seminar, Industry Hills Sheraton, California, November 20, (1992).

"The Design and Implementation of Vehicle Scrapping Programs," presented at the 86th Annual Meeting of the Air and Waste Management Association, Denver, Colorado, June 12, 1993.

"Air Quality Planning and Control in Beijing, China," presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, Ohio, June 19-24, 1994.

Annex A

Expert Litigation Support

1. Occasions where Dr. Sahu has provided Written or Oral testimony before Congress:

(a) In July 2012, provided expert written and oral testimony to the House Subcommittee on Energy and the Environment, Committee on Science, Space, and Technology at a Hearing entitled "Hitting the Ethanol Blend Wall – Examining the Science on E15."

2. Matters for which Dr. Sahu has have provided affidavits and expert reports include:

(b) Affidavit for Rocky Mountain Steel Mills, Inc. located in Pueblo Colorado – dealing with the technical uncertainties associated with night-time opacity measurements in general and at this steel mini-mill.

(c) Expert reports and depositions (2/28/2002 and 3/1/2002; 12/2/2003 and 12/3/2003; 5/24/2004) on behalf of the United States in connection with the Ohio Edison NSR Cases. *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (Southern District of Ohio).

(d) Expert reports and depositions (5/23/2002 and 5/24/2002) on behalf of the United States in connection with the Illinois Power NSR Case. *United States v. Illinois Power Co., et al.*, 99-833-MJR (Southern District of Illinois).

(e) Expert reports and depositions (11/25/2002 and 11/26/2002) on behalf of the United States in connection with the Duke Power NSR Case. *United States, et al. v. Duke Energy Corp.*, 1:00-CV-1262 (Middle District of North Carolina).

(f) Expert reports and depositions (10/6/2004 and 10/7/2004; 7/10/2006) on behalf of the United States in connection with the American Electric Power NSR Cases. *United States, et al. v. American Electric Power Service Corp., et al.*, C2-99-1182, C2-99-1250 (Southern District of Ohio).

(g) Affidavit (March 2005) on behalf of the Minnesota Center for Environmental Advocacy and others in the matter of the Application of Heron Lake BioEnergy LLC to construct and operate an ethanol production facility – submitted to the Minnesota Pollution Control Agency.

(h) Expert Report and Deposition (10/31/2005 and 11/1/2005) on behalf of the United States in connection with the East Kentucky Power Cooperative NSR Case. *United States v. East Kentucky Power Cooperative, Inc.*, 5:04-cv-00034-KSF (Eastern District of Kentucky).

(i) Affidavits and deposition on behalf of Basic Management Inc. (BMI) Companies in connection with the BMI vs. USA remediation cost recovery Case.

(j) Expert Report on behalf of Penn Future and others in the Cambria Coke plant permit challenge in Pennsylvania.

(k) Expert Report on behalf of the Appalachian Center for the Economy and the Environment and others in the Western Greenbrier permit challenge in West Virginia.

(l) Expert Report, deposition (via telephone on January 26, 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) in the Thompson River Cogeneration LLC Permit No. 3175-04 challenge.

(m) Expert Report and deposition (2/2/07) on behalf of the Texas Clean Air Cities Coalition at the Texas State Office of Administrative Hearings (SOAH) in the matter of the permit challenges to TXU Project Apollo's eight new proposed PRB-fired PC boilers located at seven TX sites.

(n) Expert Testimony (July 2007) on behalf of the Izaak Walton League of America and others in connection with the acquisition of power by Xcel Energy from the proposed Gascoyne Power Plant – at the State of Minnesota, Office of Administrative Hearings for the Minnesota PUC (MPUC No. E002/CN-06-1518; OAH No. 12-2500-17857-2).

(o) Affidavit (July 2007) Comments on the Big Cajun I Draft Permit on behalf of the Sierra Club – submitted to the Louisiana DEQ.

(p) Expert Report and Deposition (12/13/2007) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (Western District of Pennsylvania).

(q) Expert Reports and Pre-filed Testimony before the Utah Air Quality Board on behalf of Sierra Club in the Sevier Power Plant permit challenge.

(r) Expert Report and Deposition (October 2007) on behalf of MTD Products Inc., in connection with General Power Products, LLC v MTD Products Inc., 1:06 CVA 0143 (Southern District of Ohio, Western Division)

(s) Experts Report and Deposition (June 2008) on behalf of Sierra Club and others in the matter of permit challenges (Title V: 28.0801-29 and PSD: 28.0803-PSD) for the Big Stone II unit, proposed to be located near Milbank, South Dakota.

(t) Expert Reports, Affidavit, and Deposition (August 15, 2008) on behalf of Earthjustice in the matter of air permit challenge (CT-4631) for the Basin Electric Dry Fork station, under construction near Gillette, Wyoming before the Environmental Quality Council of the State of Wyoming.

(u) Affidavits (May 2010/June 2010 in the Office of Administrative Hearings))/Declaration and Expert Report (November 2009 in the Office of Administrative Hearings) on behalf of NRDC and the Southern Environmental Law Center in the matter of the air permit challenge for Duke Cliffside Unit 6. Office of Administrative Hearing Matters 08 EHR 0771, 0835 and 0836 and 09 HER 3102, 3174, and 3176 (consolidated).

(v) Declaration (August 2008), Expert Report (January 2009), and Declaration (May 2009) on behalf of Southern Alliance for Clean Energy et al., v Duke Energy Carolinas, LLC. in the matter of the air permit challenge for Duke Cliffside Unit 6. *Southern Alliance for Clean Energy et al., v. Duke Energy Carolinas, LLC*, Case No. 1:08-cv-00318-LHT-DLH (Western District of North Carolina, Asheville Division).

(w) Declaration (August 2008) on behalf of the Sierra Club in the matter of Dominion Wise County plant MACT.

(x) Expert Report (June 2008) on behalf of Sierra Club for the Green Energy Resource Recovery Project, MACT Analysis.

(y) Expert Report (February 2009) on behalf of Sierra Club and the Environmental Integrity Project in the matter of the air permit challenge for NRG Limestone's proposed Unit 3 in Texas.

(z) Expert Report (June 2009) on behalf of MTD Products, Inc., in the matter of *Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al.*

(aa) Expert Report (August 2009) on behalf of Sierra Club and the Southern Environmental Law Center in the matter of the air permit challenge for Santee Cooper's proposed Pee Dee plant in South Carolina).

(bb) Statements (May 2008 and September 2009) on behalf of the Minnesota Center for Environmental Advocacy to the Minnesota Pollution Control Agency in the matter of the Minnesota Haze State Implementation Plans.

(cc) Expert Report (August 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(dd) Expert Report and Rebuttal Report (September 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

(ee) Expert Report (December 2009) and Rebuttal reports (May 2010 and June 2010) on behalf of the United States in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).

(ff) Pre-filed Testimony (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(gg) Pre-filed Testimony (July 2010) and Written Rebuttal Testimony (August 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions*, No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(hh) Expert Report (August 2010) and Rebuttal Expert Report (October 2010) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana) – Liability Phase.

(ii) Declaration (August 2010), Reply Declaration (November 2010), Expert Report (April 2011), Supplemental and Rebuttal Expert Report (July 2011) on behalf of the United States in the matter of DTE Energy Company and Detroit Edison Company (Monroe Unit 2). *United States of America v. DTE Energy Company and Detroit Edison Company*, Civil Action No. 2:10-cv-13101-BAF-RSW (US District Court for the Eastern District of Michigan).

(jj) Expert Report and Deposition (August 2010) as well as Affidavit (September 2010) on behalf of Kentucky Waterways Alliance, Sierra Club, and Valley Watch in the matter of challenges to the NPDES permit issued for the Trimble County power plant by the Kentucky Energy and Environment Cabinet to Louisville Gas and Electric, File No. DOW-41106-047.

(kk) Expert Report (August 2010), Rebuttal Expert Report (September 2010), Supplemental Expert Report (September 2011), and Declaration (November 2011) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

(ll) Written Direct Expert Testimony (August 2010) and Affidavit (February 2012) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(mm) Deposition (August 2010) on behalf of Environmental Defense, in the matter of the remanded permit challenge to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(nn) Expert Report, Supplemental/Rebuttal Expert Report, and Declarations (October 2010, November 2010, September 2012) on behalf of New Mexico Environment Department (Plaintiff-Intervenor), Grand Canyon Trust and Sierra Club (Plaintiffs) in the matter of Plaintiffs v. Public Service Company of New Mexico (PNM), Civil No. 1:02-CV-0552 BB/ATC (ACE). (US District Court for the District of New Mexico).

(oo) Expert Report (October 2010) and Rebuttal Expert Report (November 2010) (BART Determinations for PSCo Hayden and CSU Martin Drake units) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

(pp) Expert Report (November 2010) (BART Determinations for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

(qq) Declaration (November 2010) on behalf of the Sierra Club in connection with the Martin Lake Station Units 1, 2, and 3. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Case No. 5:10-cv-00156-DF-CMC (US District Court for the Eastern District of Texas, Texarkana Division).

(rr) Pre-Filed Testimony (January 2011) and Declaration (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

(ss) Declaration (February 2011) in the matter of the Draft Title V Permit for RRI Energy MidAtlantic Power Holdings LLC Shawville Generating Station (Pennsylvania), ID No. 17-00001 on behalf of the Sierra Club.

(tt) Expert Report (March 2011), Rebuttal Expert Report (Jue 2011) on behalf of the United States in *United States of America v. Cemex, Inc.*, Civil Action No. 09-cv-00019-MSK-MEH (US District Court for the District of Colorado).

(uu) Declaration (April 2011) and Expert Report (July 16, 2012) in the matter of the Lower Colorado River Authority (LCRA)'s Fayette (Sam Seymour) Power Plant on behalf of the Texas Campaign for the Environment. *Texas Campaign for the Environment v. Lower Colorado River Authority*, Civil Action No. 4:11-cv-00791 (US District Court for the Southern District of Texas, Houston Division).

(vv) Declaration (June 2011) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.

(ww) Expert Report (June 2011) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).

(xx) Declaration (August 2011) in the matter of the Sandy Creek Energy Associates L.P. Sandy Creek Power Plant on behalf of Sierra Club and Public Citizen. *Sierra Club, Inc. and Public Citizen, Inc. v. Sandy Creek Energy Associates, L.P.*, Civil Action No. A-08-CA-648-LY (US District Court for the Western District of Texas, Austin Division).

(yy) Expert Report (October 2011) on behalf of the Defendants in the matter of *John Quiles and Jeanette Quiles et al. v. Bradford-White Corporation, MTD Products, Inc., Kohler Co., et al.*, Case No. 3:10-cv-747 (TJM/DEP) (US District Court for the Northern District of New York).

(zz) Declaration (February 2012) and Second Declaration (February 2012) in the matter of *Washington Environmental Council and Sierra Club Washington State Chapter v. Washington State Department of Ecology and Western States Petroleum Association,* Case No. 11-417-MJP (US District Court for the Western District of Washington).

(aaa) Expert Report (March 2012) and Supplemental Expert Report (November 2013) in the matter of *Environment Texas Citizen Lobby, Inc and Sierra Club v. ExxonMobil Corporation et al.,* Civil Action No. 4:10-cv-4969 (US District Court for the Southern District of Texas, Houston Division).

(bbb) Declaration (March 2012) in the matter of *Center for Biological Diversity, et al. v. United States Environmental Protection Agency*, Case No. 11-1101 (consolidated with 11-1285, 11-1328 and 11-1336) (US Court of Appeals for the District of Columbia Circuit).

(ccc) Declaration (March 2012) in the matter of *Sierra Club v. The Kansas Department of Health and Environment*, Case No. 11-105,493-AS (Holcomb power plant) (Supreme Court of the State of Kansas).

(ddd) Declaration (March 2012) in the matter of the Las Brisas Energy Center *Environmental Defense Fund et al., v. Texas Commission on Environmental Quality,* Cause No. D-1-GN-11-001364 (District Court of Travis County, Texas, 261st Judicial District).

(eee) Expert Report (April 2012), Supplemental and Rebuttal Expert Report (July 2012), and Supplemental Rebuttal Expert Report (August 2012) on behalf of the states of New Jersey and Connecticut in the matter of the Portland Power plant *State of New Jersey and State of Connecticut (Intervenor-Plaintiff) v. RRI Energy Mid-Atlantic Power Holdings et al.,* Civil Action No. 07-CV-5298 (JKG) (US District Court for the Eastern District of Pennsylvania).

(fff) Declaration (April 2012) in the matter of the EPA's EGU MATS Rule, on behalf of the Environmental Integrity Project

(ggg) Expert Report (August 2012) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana) – Harm Phase.

(hhh) Declaration (September 2012) in the Matter of the Application of *Energy Answers Incinerator*, *Inc.* for a Certificate of Public Convenience and Necessity to Construct a 120 MW Generating Facility in Baltimore City, Maryland, before the Public Service Commission of Maryland, Case No. 9199.

(iii) Expert Report (October 2012) on behalf of the Appellants (Robert Concilus and Leah Humes) in the matter of Robert Concilus and Leah Humes v. Commonwealth of Pennsylvania Department of Environmental Protection and Crawford Renewable Energy, before the Commonwealth of Pennsylvania Environmental Hearing Board, Docket No. 2011-167-R.

(jjj) Expert Report (October 2012), Supplemental Expert Report (January 2013), and Affidavit (June 2013) in the matter of various Environmental Petitioners v. North Carolina DENR/DAQ and Carolinas Cement Company, before the Office of Administrative Hearings, State of North Carolina.

(kkk) Pre-filed Testimony (October 2012) on behalf of No-Sag in the matter of the North Springfield Sustainable Energy Project before the State of Vermont, Public Service Board.

(lll) Pre-filed Testimony (November 2012) on behalf of Clean Wisconsin in the matter of Application of Wisconsin Public Service Corporation for Authority to Construct and Place in Operation a New Multi-Pollutant Control Technology System (ReACT) for Unit 3 of the Weston Generating Station, before the Public Service Commission of Wisconsin, Docket No. 6690-CE-197.

(mmm) Expert Report (February 2013) on behalf of Petitioners in the matter of Credence Crematory, Cause No. 12-A-J-4538 before the Indiana Office of Environmental Adjudication.

(nnn) Expert Report (April 2013), Rebuttal report (July 2013), and Declarations (October 2013, November 2013) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

(ooo) Expert Report (May 2013) and Rebuttal Expert Report (July 2013) on behalf of the Sierra Club in connection with the Luminant Martin Lake Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 5:10-cv-0156-MHS-CMC (Eastern District of Texas, Texarkana Division).

(ppp) Declaration (August 2013) on behalf of A. J. Acosta Company, Inc., in the matter of A. J. Acosta Company, Inc., v. County of San Bernardino, Case No. CIVSS803651.

(qqq) Comments (October 2013) on behalf of the Washington Environmental Council and the Sierra Club in the matter of the Washington State Oil Refinery RACT (for Greenhouse Gases), submitted to the Washington State Department of Ecology, the Northwest Clean Air Agency, and the Puget Sound Clean Air Agency.

(rrr) Statement (November 2013) on behalf of various Environmental Organizations in the matter of the Boswell Energy Center (BEC) Unit 4 Environmental Retrofit Project, to the Minnesota Public Utilities Commission, Docket No. E-015/M-12-920.

(sss) Expert Report (December 2013) on behalf of the United States in *United States of America v. Ameren Missouri*, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).

(ttt) Expert Testimony (December 2013) on behalf of the Sierra Club in the matter of Public Service Company of New Hampshire Merrimack Station Scrubber Project and Cost Recovery, Docket No. DE 11-250, to the State of New Hampshire Public Utilities Commission.

(uuu) Expert Report (January 2014) on behalf of Baja, Inc., in Baja, Inc., v. Automotive Testing and Development Services, Inc. et. al, Civil Action No. 8:13-CV-02057-GRA (District of South Carolina, Anderson/Greenwood Division).

(vvv) Declaration (March 2014) on behalf of the Center for International Environmental Law, Chesapeake Climate Action Network, Friends of the Earth, Pacific Environment, and the Sierra Club (Plaintiffs) in the matter of Plaintiffs v. the Export-Import Bank (Ex-Im Bank) of the United States, Civil Action No. 13-1820 RC (United States District Court for the District of Columbia).

(www) Direct Prefiled Testimony (June 2014) on behalf of the Michigan Environmental Council and the Sierra Club in the matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery (PSCR) Plan in its Rate Schedules for 2014 Metered Jurisdictional Sales of Electricity, Case No. U-17319 (Michigan Public Service Commission).

(xxx) Expert Report (June 2014) on behalf of ECM Biofilms in the matter of the US Federal Trade Commission (FTC) v. ECM Biofilms (FTC Docket #9358).

3. Occasions where Dr. Sahu has provided oral testimony <u>in depositions, at trial or in similar proceedings</u> include the following:

(yyy) Deposition on behalf of Rocky Mountain Steel Mills, Inc. located in Pueblo, Colorado – dealing with the manufacture of steel in mini-mills including methods of air pollution control and BACT in steel mini-mills and opacity issues at this steel mini-mill.

(zzz) Trial Testimony (February 2002) on behalf of Rocky Mountain Steel Mills, Inc. in Denver District Court.

(aaaa) Trial Testimony (February 2003) on behalf of the United States in the Ohio Edison NSR Cases, *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (Southern District of Ohio).

(bbbb) Trial Testimony (June 2003) on behalf of the United States in the Illinois Power NSR Case, *United States v. Illinois Power Co., et al.*, 99-833-MJR (Southern District of Illinois).

(cccc) Deposition (10/20/2005) on behalf of the United States in connection with the Cinergy NSR Case. *United States, et* al. *v. Cinergy Corp., et al.*, IP 99-1693-C-M/S (Southern District of Indiana).

(dddd) Oral Testimony (August 2006) on behalf of the Appalachian Center for the Economy and the Environment re. the Western Greenbrier plant, WV before the West Virginia ????.

(eeee) Oral Testimony (May 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) re. the Thompson River Cogeneration plant before the Montana Board of Environmental Review.

(ffff) Oral Testimony (October 2007) on behalf of the Sierra Club re. the Sevier Power Plant before the Utah Air Quality Board.

(gggg) Oral Testimony (August 2008) on behalf of the Sierra Club and Clean Water re. Big Stone Unit II before the South Dakota Board of Minerals and the Environment.

(hhhh) Oral Testimony (February 2009) on behalf of the Sierra Club and the Southern Environmental Law Center re. Santee Cooper Pee Dee units before the South Carolina Board of Health and Environmental Control.

(iiii) Oral Testimony (February 2009) on behalf of the Sierra Club and the Environmental Integrity Project re. NRG Limestone Unit 3 before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(jjjj) Deposition (July 2009) on behalf of MTD Products, Inc., in the matter of *Alice Holmes and Vernon Holmes v. Home Depot USA*, *Inc.*, *et al*.

(kkkk) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Coleto Creek coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(llll) Deposition (October 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(mmmm) Deposition (October 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

(nnnn) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Tenaska coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (April 2010).

(oooo) Oral Testimony (November 2009) on behalf of the Environmental Defense Fund re. the Las Brisas Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(pppp) Deposition (December 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(qqqq) Oral Testimony (February 2010) on behalf of the Environmental Defense Fund re. the White Stallion Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(rrrr) Deposition (June 2010) on behalf of the United States in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).

(ssss) Trial Testimony (September 2010) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, State of Maryland, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case in US District Court in the Western District of Pennsylvania. *Plaintiffs v. Allegheny Energy Inc., et al.*, 2:05cv0885 (Western District of Pennsylvania).

(tttt) Oral Direct and Rebuttal Testimony (September 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(uuuu) Oral Testimony (September 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(vvvv) Oral Testimony (October 2010) on behalf of the Environmental Defense Fund re. the Las Brisas Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(wwww) Oral Testimony (November 2010) regarding BART for PSCo Hayden, CSU Martin Drake units before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(xxxx) Oral Testimony (December 2010) regarding BART for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(yyyy) Deposition (December 2010) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

(zzzz) Deposition (February 2011 and January 2012) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

(aaaaa) Oral Testimony (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

(bbbbb) Deposition (August 2011) on behalf of the United States in *United States of America v. Cemex, Inc.*, Civil Action No. 09-cv-00019-MSK-MEH (US District Court for the District of Colorado).

(ccccc) Deposition (July 2011) and Oral Testimony at Hearing (February 2012) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.

(ddddd) Oral Testimony at Hearing (March 2012) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

(eeeee) Oral Testimony at Hearing (April 2012) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).

(fffff) Oral Testimony at Hearing (November 2012) on behalf of Clean Wisconsin in the matter of Application of Wisconsin Public Service Corporation for Authority to Construct and Place in Operation a New Multi-Pollutant Control Technology System (ReACT) for Unit 3 of the Weston Generating Station, before the Public Service Commission of Wisconsin, Docket No. 6690-CE-197.

(ggggg) Deposition (March 2013) in the matter of various Environmental Petitioners v. North Carolina DENR/DAQ and Carolinas Cement Company, before the Office of Administrative Hearings, State of North Carolina.

(hhhhh) Deposition (August 2013) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

(iiiii) Deposition (August 2013) on behalf of the Sierra Club in connection with the Luminant Martin Lake Case. Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC, Civil Action No. 5:10-cv-0156-MHS-CMC (Eastern District of Texas, Texarkana Division).

(jjjjj) Deposition (February 2014) on behalf of the United States in *United States of America v. Ameren Missouri*, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).

(kkkkk) Trial Testimony (February 2014) in the matter of *Environment Texas Citizen Lobby, Inc and Sierra Club v. ExxonMobil Corporation et al.*, Civil Action No. 4:10-cv-4969 (US District Court for the Southern District of Texas, Houston Division).

(lllll) Trial Testimony (February 2014) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

(mmmmm) Deposition (June 2014) on behalf of ECM Biofilms in the matter of the US Federal Trade Commission (FTC) v. ECM Biofilms (FTC Docket #9358).

Supplemental Comments to the Arkansas Department of Environmental Quality on White Bluff Draft Permit (No.: 0263-AOP-R8)

By

Dr. Ranajit (Ron) Sahu, Consultant

1. Sierra Club has asked me to review the assertions made by Entergy Arkansas that the addition of activated carbon injection (ACI) combined with halide coal pretreatment, will reduce the particulate matter (PM) emissions from the White Bluff plant's two primary stacks, each serving the two units. I have over 15 years of experience evaluating the operation of coal plant pollution control operations. Specifically, I have over 5 years of experience dealing with the application of sorbent technologies such as ACI to reduce mercury emissions, and their resulting impacts on particulate controls such as electrostatic precipitators (ESPs).

2. I provided a preliminary technical report on the White Bluff ACI project that I understand Sierra Club submitted to the Arkansas Department of Environmental Quality (ADEQ) as Exhibit 1 to Sierra Club's preliminary comments on the Draft White Bluff permit. In that report, I concluded that Entergy's claim of a predicted reduction in PM emissions was unjustified and unreliable. In fact, the best evidence indicates that the ACI project will cause an increase in PM emissions from the White Bluff plant of over 22 tons per year.

3. I provide these supplemental comments on Entergy's justification for the White Bluff ACI project.

4. In any analysis provided in a regulatory context, it is critically important that the entity performing the analysis provide all inputs and assumptions used so that the regulatory agency and others may assess the reliability and accuracy of the analysis. The New Source Review (NSR) analysis provided by Entergy to support the ACI project fails to meet this standard. Its work is almost entirely unreviewable and unverifiable because of a failure to provide support for the necessary inputs and assumptions or, in some cases, the inputs and assumptions themselves. I pointed out several of these failings in my initial comments on this project and add further failures of transparency here.

5. Entergy has not provided the inputs and assumptions used in the Aurora model that the company used to estimate projected future emissions of all relevant pollutants. Entergy used this model to create projected heat input numbers for Units 1 and 2 of the White Bluff plant for future years. These heat input figures were then used by Entergy for all of its future emissions calculations. Without the inputs and assumptions used to generate these heat input figures, the emissions calculations themselves are not verifiable or even understandable. Certainly no regulatory agency could rely on these figures given the "black box" nature of the Aurora model and its use by Entergy. Due to the lack of transparency for this modeling and the calculations, ADEQ could not have adequately reviewed or assessed the White Bluff NSR emissions calculations.

6. There is another problem with Entergy's projection of the future heat inputs at each Unit. For a given future year, Entergy has adjusted (actually inflated by roughly 5%) the already-opaque Aurora projected heat input estimate to account for a "discrepancy" between how Entergy reports heat input to the U.S. EPA Clean Air Markets Division versus what it believes the "accurate" heat input figure should be. In any case, in order to make this adjustment, Entergy states that it derived presumably more accurate heat input numbers from fuel usage at each Unit and the heating value of the fuel(s). But, here again, Entergy simply provides only its so-called accurate final heat input values without any data to support the fuel usage and heating value inputs. Nor does Entergy provide any discussion as to why the heat input calculated from these parameters would be necessarily more accurate than what it reports to the U.S. EPA. This is a further issue with transparency and a further reason why Entergy's calculations of NSR emissions cannot be verified or relied upon. Separately, since Entergy is obligated to provide accurate data to the U.S. EPA, it is not clear why it is not doing so or why Entergy has not performed this correction for all of the data that it has provided and continues to provide to U.S. EPA.

Ranajit Sahu

(Ranajit Sahu)

Comments to the Arkansas Department of Environmental Quality

on White Bluff Proposed Permit Permit No.: 0263-AOP-R8

By

Dr. Ranajit (Ron) Sahu, Consultant

April 2015

Introduction

Sierra Club and members of the public provided numerous technical comments addressing deficiencies in the Arkansas Department of Environmental Quality's ("ADEQ") draft permit issuance for the White Bluff power plant. To the extent the ADEQ has even responded to these comments, the responses, as discussed below, have been, at best, disappointing and, in some instances, misleading. I urge EPA to require more rigorous examination of the issues raised by Sierra Club and the public. Separately, in its comments, the ADEQ, without justification, also proposes to relax several permit conditions that will considerably weaken the compliance monitoring aspects of the permit. Because these changes were made after ADEQ initially issued a draft permit, this is my first opportunity to comment on them and these most-recent changes should be reversed as well.

Issue 1. Emissions of Particulate Matter

A significant issue of concern raised by the public was the likelihood that emissions of particulate matter would likely increase upon the introduction of various unspecified sorbents into the exhaust gas streams from the White Bluff plant. In my technical comments on the draft permit, my analysis showed that PM emissions would increase significantly triggering Best Available Control Technology ("BACT") review. The Statement of Basis put forth by the ADEQ suggests that these emissions will decrease after the project as follows:

Pollutant (tpy)	Check if Chargeable Emission	Old Permit	New Permit	Change in Emissions	Permit Fee Chargeable Emissions	Annual Chargeable Emissions
PM		6680.8	6607	-73.8	0	4000
PM_{10}		6429.8	6414.8	-15		

Sorbents are proposed to be used in order to bring these units into compliance with the Mercury and Air Toxics Standards ("MATS") rule. In comments submitted to ADEQ, based on my reasoned technical analysis using publicly available documents, I suggested that the ADEQ look more closely at this issue and not merely accept the utility's unsupported emission calculations and underlying assumptions. The ADEQ chose to simply accept the utility's initial analysis.

Yet, in a vindication of my comments, the utility itself made the following comment which appears to indicate some doubt that PM emissions will decrease:

> "[T]o mitigate any risk of an increase in FPM emissions associated with ACI, Entergy plans to replace the traditional transformer/rectifier ("T/R") set in the first fields of each ESP at White Bluff with high-frequency power supplies ("HFPS") as part of the mercury controls project at each unit (SN-01 and SN-02), HFPS technology allows for a smooth and more stable output voltage compared to the voltage peaks and valleys which can occur with a conventional T/R set. This improvement in ESP field voltage stability is expected to result in additional decreases in filterable PM emissions from each unit."

ADEQ Response to Comments at 6-7.

In addition, the utility suggests (and the ADEQ accepted) the following language with regards to PM emissions:

> "However, Entergy anticipates no increase in filterable particulate matter as measured by EPA Reference Method 5."

Clearly, anticipating "no increase" is a far cry from confidently asserting that PM emissions would decrease to the tune of over 70+ tons per year as noted in the Statement of Basis. And, in any event, my earlier analysis indicated that PM emissions are more likely to increase by over 20 tons per year.

All of the above begs the obvious question: Why, if it were so confident that emissions of PM would decrease as noted in its permit application (as is blindly accepted by the ADEQ), would the utility propose to "mitigate any risk" of PM increases via ESP upgrades? It makes no sense to upgrade the ESP in the vague manner suggested if the utility were confident that PM would not increase. The fact, as shown in my initial technical reports, that there are significant unknowns with regards to future PM emissions. There is insufficient testing for PM in the units themselves, using the proper quantities and actual types of sorbents that the utility intends to actually use. Perhaps, in finally recognizing these important data gaps and deficiencies, the utility has decided to upgrade its current PM controls. While that is a start (though the utility's pledge appears to be nonbinding), the brief description of the upgrades proposed, as described above, do not provide sufficient and reliable evidence that they will be adequate to protect Arkansans from increased future PM emissions. I urge the EPA to require a more complete record of future PM emissions—based on testing and facts and not data gaps. I also urge the EPA to require that the utility provide a complete engineering assessment of the planned upgrades to the ESPs.

The ADEQ's response to the comments on this PM issue (Comment #1 and Comment #32), are provided below in italics. My rebuttal to each point is provided in brackets.

> *"ADEQ takes issue with the speculative nature of this comment."*

[Recognizing uncertainty in emission calculations is not "speculative." It is not the public's responsibility but rather that of the utility and, most importantly, the agency's to provide support for the emission calculations. In any case, there is nothing speculative about the likelihood that emissions of PM would increase—as demonstrated by my initial analysis and the additional steps in enhancing particulate controls being proposed by the utility and the careful rewording suggested by the utility.]

> *"The commenter provides no definitive information to refute Entergy's analysis."*

[My analysis relied on all of the publicly available information. It is impermissible to ask the public for "definitive" information when the ADEQ and the utility have themselves not asked for, used, or relied upon "definitive" information. ADEQ's response in this regard is ironic given that its entire consideration of this issue is premised on an analysis with large data gaps and many unfounded assumptions.]

> *"The Department responds to specific issues raised in the comment as follows:*
> *1. Unspecified ESP design parameters are cited as potentially affecting ACI emissions. This claim is misplaced and irrelevant since the analyses provided by Entergy are based on actual trial testing of ACI and not an analysis of ESP design parameters."*

[Actually, ADEQ's response is misplaced and the comment is on point. The fact that the utility has little to no confidence in the prior "actual trial testing" is amply demonstrated by its now willingness to upgrade the ESPs as discussed earlier.]

> *"2. Changes in capacity or ACI injection during the trial testing may affect emission rates. This statement is speculative at best. Moreover, it is not relevant since the analyses provided by Entergy were based on the difference in emission rates with and without ACI, not any total emission rate."*

[ADEQ's response makes no sense whatsoever. Of course, changes in unit operating capacity and/or sorbent injection rates will affect the resultant emissions rates and total mass emissions of PM from any test. Therefore, if test conditions themselves are at issue, the results of the tests cannot be relied upon to infer emission rates or mass emissions at actual unit operating conditions different from test conditions—unless the test conditions are representative of unit operating conditions and sorbent addition conditions (i.e., same sorbents, similar quantities, similar injection locations, etc.). That is simply a fact that the ADEQ failed to appropriately consider.]

> *"3. ACI emissions are above 22 tpy based on usage and ESP efficiency. The commenter incorrectly applied ESP efficiency to bulk activated carbon. It is not possible to estimate an emission rate in this manner. ESP efficiencies are related to particle size and the commenter made no attempt to estimate the ESP collection efficiency for ACI."*

[This response is audacious. I could not find anywhere in the record, the relationship between particle size and ESP efficiency for the specific units at this plant. Nor could I find any instance in which either the utility or the ADEQ used this approach for estimating emissions. While it is technically correct, it is not within the purview of the public to gather this type of information to base its emission estimates since this type of technical information is only available to the utility (and, of course, to the ADEQ should the agency request it from the utility). Overall ESP efficiency is widely used to estimate emission rates from ESPs. But, if the utility and/or the ADEQ wants to refine its calculations in the manner suggested, it should provide the suggested ESP/PM size versus efficiency curves for each ESP at White Bluff, along with underlying ESP operating parameters (because they affect this relationship). It should also provide these curves including the effects or representative sorbent addition, since the sorbent addition will affect the resistivity of the collected particles, thereby affecting the size versus efficiency curves. The utility and ADEQ should also provide the expected particle size distribution of the modified particulate loading to the ESP, including the added sorbent mass. Upon receiving these additional technical data and information, I would be happy to consider and refine my calculations.]

> *"4. Road emissions will likely cause emissions subject to PSD. These increases in road emissions are neither quantified or specified by the commenter."*

[Again, the response by the ADEQ is audacious. There is not enough information to conduct this calculation in the public record. Only the utility would have that information. And, it is the regulator's job to ask for and conduct its own independent analysis of such emissions. The ADEQ mistakenly believes that it is the public's obligation to (a) gather information from the utility; and (b) conduct the calculations. It is mistaken.]

> *"Response to Comment (#32)*
> *No changes to the permit have been made. PSD regulations allow a source to compare "baseline actual emissions" with "projected actual emissions". Entergy submitted emission projections showing that the project will not result in a significant emissions increase for any pollutant using the methods described in PSD regulations for calculating whether there is significant emissions increase."*

[This response simply punts the issue. The whole point of the comment, of course, was that "projected actual emissions" were incorrect. Instead of addressing that, the ADEQ provides no response.]

For all of the reasons above, I urge the EPA to require a fuller public record of underlying facts that can support a proper estimate of future PM emissions from these units. It should be evident that (a) there are large data gaps, which cannot preclude a reasonable probability that PM emissions would increase in the future; (b) it is the utility and ADEQ's responsibility to fill these gaps and to support their position that PM emissions will not increase; (c) the SOB is simply incorrect in projecting significant emissions decreases, when the best the utility can do is "anticipate" no emissions increases; (d) ADEQ's responses to thoughtful public comments do not reveal a serious attempt to consider the issues raised.

Issue 2: Opacity

Commenters note that opacity is likely to increase if PM emissions increase given the widely acknowledged relationship between the two. The ADEQ's response is noted below.

> *"Response to Comment (4)*
> *Comments regarding the permittee's opacity limits are outside the scope of this action. This permitting action is limited to those portions regarding incorporation of the applicable MATS requirements."*

[The ADEQ fails to recognize that the manner of complying with MATS involves injection of sorbents which will likely increase PM emissions, and therefore could adversely affect opacity.]

Issue 3: Testing

The permit, at Condition 14, excerpted below, provides for PM and PM10 testing "every year." It is not clear if this is consistent with the MATS testing requirement for filterable PM, which could be as frequent as quarterly, depending on the compliance option selected under MATS. Or, the utility could choose to comply using PM CEMS. The ADEQ should make the testing frequency consistent with the requirements of the MATS Rule.

14. TESTING REQUIREMENTS:

The permit requires testing of the following sources.

SN	Pollutants	Test Method	Test Interval	Justification
01 and 02	CO	10	Every 5 years	To demonstrate compliance with CO emission rates.
01 and 02	PM	5 and 202	Every year	To demonstrate compliance with PM emission rates.
01 and 02	PM_{10}	201A and 202	Every year	To demonstrate compliance with PM_{10} emission rates.

Issue 4: Exclusion of Substituted Data from Compliance Assessment

In the following instances noted below, the utility requested that substituted data for various CEMS not be used for compliance, and the ADEQ agreed – without any response or justification.

> *"Entergy requests that the following sentence from Specific Condition 12 be added as the fourth sentence of Specific Condition 4. "Data Substituted in accordance with 40 CFR Part 75 for missing and lor invalid data will not be used for compliance with Specific Condition # 1."*
> *Response to Comment (10) "The requested sentence has been added.""*

“Comment #11
Specific Condition 5 - Page 19: For the same reasons outlined above, Entergy requests that the following sentence be added as the fourth sentence of Specific Condition 5. "Data substituted in accordance with 40 CFR Part 75 for missing and/or invalid data will not be used for compliance with Specific Condition # 1."
Response to Comment “The requested sentence has been added.””

ADEQ’s acceptance of Entergy’s suggestion is improper. The purpose of having the substituted data provisions in the regulations is to encourage the source to maintain its CEMS equipment in valid, operational conditions at all times—so that it does not have to use the “missing data” substitution provisions to begin with. The ADEQ action above removes this incentive completely. Thus, if the CEMS were down for long periods of time, Entergy has no risk or incentive to bring them back to operational status, since it is exempt from using the substituted data for compliance purposes. The ADEQ approval of these requests should be revoked.

ADEQ
ARKANSAS
Department of Environmental Quality

January 22, 2015

Tony G. Mendoza, Staff Attorney
Sierra Club Environmental Law Program
85 Second Street, 2nd Floor
San Francisco, CA 94105

Dear Mr. Mendoza:

After considering the facts and requirements of A.C.A. §8-4-101 et seq. as referenced by §8-4-304, and implementing regulations, I have determined that Permit No. 0263-AOP-R8 for the construction and operation of equipment at Entergy Arkansas, Inc. (White Bluff Plant) located at 1100 White Bluff Road, Redfield, Arkansas to be issued and effective on the date specified in the permit, unless a Commission review has been properly requested under Arkansas Department of Pollution Control & Ecology Commission's Administrative Procedures, Regulation 8.

The final permit decision is to issue the permit with the changes indicated in the attached Response to Comments.

The applicant or permittee and any other person submitting public comments on the record may request an adjudicatory hearing and Commission review of the final permitting decisions as provided under Chapter Six of Regulation No. 8, Administrative Procedures, Arkansas Pollution Control and Ecology Commission. Such a request shall be in the form and manner required by Regulation 8.603, including filing a written Request for Hearing with the APC&E Commission Secretary at 101 E. Capitol Ave., Suite 205, Little Rock, Arkansas 72201. If you have any questions about filing the request, please call the Commission at 501-682-7890.

Copies of the complete final permit decision may be obtained by contacting the Air Permit Branch of the Department at 501 682-0738 or Help-Air-Permits@adeq.state.ar.us.

Sincerely,

Mike Bates
Chief, Air Division

Enclosures: Certificate of Service, Response to Comments

RESPONSE TO COMMENTS

ENTERGY ARKANSAS, INC. (WHITE BLUFF PLANT)
PERMIT #0263-AOP-R8
AFIN: 35-00110

On June 11, 2014 and June 29, 2014, the Director of the Arkansas Department of Environmental Quality ("ADEQ" or "Department") gave notice of a draft permitting decision for the above referenced facility. During the comment period written and oral comments on the draft permitting decision were submitted on behalf of the facility and the public. The Department's response to these issues follows.

Note: The following page numbers and condition numbers refer to the draft permit. These references may have changed in the final permit based on changes made during the comment period.

Commenter	Comments Begins with:	Ends with Comment #
William Moore, Sierra Club	1	4
Entergy	5	26
Chester A. Sautter	27	27
Barbara Jarvis	28	28
Glen Hooks	29	29
Tony Mendoza, Sierra Club	30	33
Robert Walker	34	34
Christina Mullinax	35	35
Mike Brown	36	36
Chris Bodiford	37	37
Rel Corbin	38	38
Shelly Buonaiuto	39	39
Beaux Franks	40	40
Ms. Scharmel Roussel	41	41

Comment #1

The technical justification for the proposed activated carbon injection ("ACI") project and the claim that this project will not increase particulate matter ("PM") emissions is flawed and incomplete and, in fact, PM-10 emissions are likely to exceed the PSD significance levels and trigger the requirement to obtain a prevention of significant deterioration ("PSD") permit and apply best available control technology ("BACT").

The Sierra Club has retained Dr. Ranajit (Ron) Sahu to evaluate Entergy's assertion that PM emissions will decrease following the addition of ACI to its operations at White Bluff. Dr. Sahu's Preliminary Report on this issue is attached as Exhibit 1, and his observations and conclusions are hereby incorporated into this comment letter.

Among other things, Dr. Sahu concludes that Entergy's technical support for its ACI project is fundamentally flawed in numerous ways, and is based on unreliable and insufficient technical information and documentation. Dr. Sahu asserts that without much more reliable and comprehensive technical support for this project, ADEQ cannot reasonable accept Entergy's assertion that PM emissions will decrease as a result of the addition of ACI. On the contrary, Dr. Sahu concludes that the filterable PM from the proposed ACI project will likely cause a collective increase of filterable PM of approximately 22.8 tons per year (from both increased particulate loading into the electrostatic precipitators ("ESPs") and increased road dust PM), which is sufficient to trigger PSD applicability and the requirement to apply BACT. On this basis alone, Dr. Sahu claims that the Draft White Bluff Permit cannot lawfully be issued.

Dr. Sahu makes the following statements in his preliminary report:

> What is clear is that with ACI addition, the particulate loading into the ESPs will increase. The Road Emission Calculations spreadsheet provided by Entergy states that the maximum annual ACI Injection Rate (or usage) will be 2,278 tons/year for both units. Assuming an ESP filterable PM efficiency of 99% (which is generous, given the total lack of information on ESP design, condition, and operating parameters) for each ESP, the incremental emissions of filterable PM as a result of the additional ACI loading is approximately 2,278*(1-0.99) = 22.8 tons/year. In addition, as Entergy notes, there are additional increases in fugitive PM emissions as a result of road traffic, ash hauling, ACI transport, etc. Collectively, the expected increase in filterable PM emissions, therefore, is likely above 22.8 tons/year. This exceeds the PSD Significant Emissions Rate for PM_{10}, which is 15 tons/year.1 [40 C.F.R. § 52.21(b)(23)(i). Thus, it is more likely than not that the addition of ACI, as proposed by Entergy for White Bluff Units 1 and 2, will trigger PSD review for this pollutant. This means that the application and permit are incomplete, since Entergy has not provided a BACT analysis, or any ambient air quality modeling analysis, or any of the other PSD application requirements (such as impacts to Air Quality Related Values), etc.

Id. at 5.

Based on Dr. Sahu's assessment, Sierra Club contends that there is no basis for ADEQ to accept Entergy's assertion that PM emissions will decrease. Sierra Club claims that the addition of ACI will likely increase PM emissions at White Bluff sufficient to trigger PSD review for this pollutant. For these and all the reasons discussed in Dr. Sahu's preliminary report, Sierra Club asserts that the Draft White Bluff Permit cannot lawfully be issued.

Response to Comment

ADEQ takes issue with the speculative nature of this comment. The commenter provides no definitive information to refute Entergy's analysis. The Entergy analysis studied the effect of ACI on emissions based on trial testing of White Bluff Unit 2 and analysis of coal used at the facility. This testing provided quantifiable numerical data indicating a reduction in particulate emissions with ACI. The information provided by the commenter provides several hypothetical and speculative arguments peppered with phrases such as "is likely" and "more likely than not". The Department responds to specific issues raised in the comment as follows:

1. *Unspecified ESP design parameters are cited as potentially affecting ACI emissions.* This claim is misplaced and irrelevant since the analyses provided by Entergy are based on actual trial testing of ACI and not an analysis of ESP design parameters.

2. *Changes in capacity or ACI injection during the trial testing may affect emission rates.* This statement is speculative at best. Moreover, it is not relevant since the analyses provided by Entergy were based on the difference in emission rates with and without ACI, not any total emission rate.

3. *ACI emissions are above 22 tpy based on usage and ESP efficiency.* The commenter incorrectly applied ESP efficiency to bulk activated carbon. It is not possible to estimate an emission rate in this manner. ESP efficiencies are related to particle size and the commenter made no attempt to estimate the ESP collection efficiency for ACI.

4. *Road emissions will likely cause emissions subject to PSD.* These increases in road emissions are neither quantified or specified by the commenter.

Comment #2

The draft White Bluff permit cannot lawfully be issued because no adequate demonstration has been performed, and ADEQ has no reasonable basis for concluding, that the White Bluff plant and the proposed changes to be made thereto will not result in interference with attainment of the NAAQS.

As addressed above, the proposed ACI project covered by the draft White Bluff permit is likely to result in an increase in PM emissions that is sufficient to trigger PSD applicability. Nearby Pulaski County, Arkansas is currently on the brink of exceeding the new annual $PM_{2.5}$ National Ambient Air Quality Standard ("NAAQS") primary standards and may well be designated as non-attainment for that standard in 2014. See 12/5/13 Letter from Gov. Mike Beebe to EPA regarding NAAQS designations. In light of surrounding ambient air quality, ADEQ must ensure that any modified permits for major sources of particulate matter do not interfere with attainment of the NAAQS.

In addition, SO_2 modeling that Sierra Club has performed has revealed that the White Bluff plant's allowable and actual SO_2 emissions are causing violations of the 1- hour average NAAQS for SO_2. *See* AERMOD Modeling of SO_2 Impacts of the Entergy White Bluff Coal Plant, prepared for Sierra Club by hanh T. Tran, AMI Environmental, September 28, 2011, at 6 (Table 2) (Ex. 2). Despite these facts, neither ADEQ nor anyone else has performed any air modeling analysis or other comparable demonstration to show that the White Bluff Plant and the proposed modification projects covered by the draft White Bluff Permit will not interfere with attainment of the NAAQS or otherwise cause air pollution that is harmful to human health. For this reason, the draft White Bluff Permit cannot be lawfully issued.

There are many provisions in state law, the Clean Air Act, and the Arkansas SIP that require air modeling in this situation or at least some substantive demonstration that NAAQS attainment will not be interfered with and that injurious air pollution will not result as a consequence of this permit. *See* APCEC Reg. 18.302; APCEC Reg. 19.402; APCEC Reg. 19.502; APCEC Reg. 26; Clean Air Act Section 110(a)(2)(C); 40 C.F.R. § 51.160-51.164.

Sierra Club understands that in April 2013, the Arkansas Legislature and governor enacted a new law, Act 1302, that prohibits ADEQ from requiring a permit applicant to submit air quality modeling to demonstrate compliance with the NAAQS, and prohibits ADEQ from undertaking its own modeling or even considering modeling submitted by a third-party without the applicant's consent. This law does contain exceptions for new source applications and sources subject to PSD review. Sierra Club's understanding is that ADEQ's previous practice of conducting air quality modeling for Title V permit renewals was integral to ADEQ's strategy for assuring compliance with the NAAQS. Indeed, Act 1302 now requires ADEQ to develop "NAAQS state implementation plans," presumably to fill the gap left in Arkansas's plan for assuring compliance with the NAAQS once ADEQ is no longer permitted to follow its previous practices. EPA has also expressed concern about the implications of Act 1302 for Arkansas's legal authority to ensure attainment of the NAAQS.

In its Statement of Basis for this permit, ADEQ explains that pursuant to Act 1302, no air dispersion modeling was performed, and that "criteria pollutants were not evaluated for impacts on the NAAQS." (Statement of Basis at p. 3). Combined with the flawed PSD applicability analysis submitted by Entergy, ADEQ has not satisfied state law and SIP requirements to ensure that the NAAQS are attained and that public health is protected. This deficiency must be corrected, and ADEQ must issue a revised draft permit for public review.

Response to Comment

The Department disagrees with the comment. The permit decision does change the previously issued and effective p ermit. However, the changes involved in this action are not a "modification" as that term is defined in Arkansas Pollution Control & Ecology Commission ("APC&EC") Regulation 19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable. Finally, the incorporation of the applicable MATS requirements does not impact SO_2 emissions at the White Bluff units. Therefore, the comments regarding modeling of SO_2 emissions are outside the scope of the permitting action.

Comment #3

The draft White Bluff permit should not be issued due to a lack of enforceability and specificity concerning the identification and description of the proposed air pollution control equipment and applicable requirements.

Response to Comment

Specific Conditions #29 through #64 of the draft permit incorporate the applicable requirements of 40 CFR Part 63, Subpart UUUUU. These conditions list emission standards, compliance methods, recordkeeping, and reporting provisions of the subpart. Those conditions will become enforceable upon final action on the permit. The identification and description of the proposed pollution control project can be found on Page 5 of the draft permit. ADEQ disagrees with the commenter's statements that the permit is lacking in enforceability and specificity. No change to the draft permit will be made.

Comment #4

The draft White Bluff permit is unlawful and should not be issued because it unlawfully fails to include or unlawfully relaxes or revises federally enforceable SIP limitations on opacity applicable to White Bluff Units 1 and 2.

The complete comment can be found with the record, however, the commenter's major issues for opacity include:

1. General discussion on the importance of opacity limits, and the relationship between opacity and PM emissions;
2. A review of the Arkansas SIP's opacity regulations;
3. A review of the Federal opacity requirements found in 40 C.F.R. Part 60, Subpart D;
4. A review of the permit condition(s) that streamlined/merged the Arkansas SIP and Federal opacity requirements into a hybrid limit;
5. An argument that hybrid limit found in the permit is less stringent; and
6. An argument that the hybrid opacity condition(s) found in the permit are unlawfully allowing for startup/shutdown exemptions.

Response to Comment

Comments regarding the permittee's opacity limits are outside the scope of this action. This permitting action is limited to those portions regarding incorporation of the applicable MATS requirements.

Furthermore, the Commenter's argument is untimely raised. Specifically, the facility's first condition concerning opacity was initially incorporated into the White Bluff facility's 2005 Title V permit renewal, 263-AOP-R3. The Commenter failed to submit comments on the affected permit provisions at that time that related to opacity and is therefore precluded from raising the issue now.

Notwithstanding the fact that the comment is untimely raised, the permit contains the correct New Source Performance Standards (hereinafter "NSPS") and SIP opacity limits. The NSPS limit is contained in Specific Condition 3 and again in Specific Condition 6, "*Opacity shall not exceed 20 percent except for one six-minute period per hour of not more than 27 percent opacity*". The SIP limit is contained in Specific Condition 28, "*shall not exceed 20% opacity* *except that emissions greater than 20% opacity but not exceeding 60% opacity will be allowed for not more than six (6) minutes in the aggregate in any consecutive 60-minute period, provided such emissions will not be permitted more than three (3) times during any 24-hour period.* " but it is "*held in abeyance provided that opacity does not exceed 20% except that emissions greater than 20% opacity but not exceeding 27% opacity will be allowed for not more than one 6-minute period per hour, provided such emissions will not be permitted more than ten (10) times per day.*"

The alternative limit in Specific Condition 28 matches the NSPS except that emissions over 20% but less than 27% are limited to 10 times per day, whereas the NSPS has no such limit (theoretically 24 times per day, i.e. once every hour). Therefore the limit is in fact more stringent than the NSPS.

The alternative limit is different from the SIP limit. The upper limit is lower at 27% rather than 60% but the number of occurrences of emissions is 10 per day as opposed to 3 times per 24 hour period. This alternative is allowable under APC&EC Reg. 19.505 and first appeared in permit 0263-AOP-R3 issued on April 28, 2005.

Specific Condition 28 further outlines actions ADEQ may take if these limits are exceeded. These actions are in accordance with Chapter 6 Upset and Emergency Conditions of Regulation 19.

The permit will therefore remain as written.

Comment #5

Summary of Permit Activity - Page 5: The seventh sentence in the second paragraph of the summary of permit activity currently reads as follows:

> "However, Entergy claims no increase in filterable particulate matter as measured by EPA Reference Method 5 is expected."

Entergy provided documentation of the expected increase in ESP efficiency resulting from the proposed mercury controls with the original December 17, 2012 submission to ADEQ for this project. This documentation included EPA RM 5 results from an engineering evaluation of ACI at White Bluff which demonstrated lower emissions of filterable PM with ACI than without. This documentation also included fly ash resistivity data obtained from the Energy and Environmental Research Center at the University of North Dakota which documented that fly ash resistivity decreased after halide treatment of the coal. Entergy expects that this decrease in fly ash resistivity will result in increased ESP collection efficiencies and will therefore result in a reduction in emissions of filterable PM.

To mitigate any risk of an increase in FPM emissions associated with ACI, Entergy plans to replace the traditional transformer/rectifier ("T/R") set in the first fields of each ESP at White Bluff with high-frequency power supplies ("HFPS") as part of the mercury controls project at each unit (SN-01 and SN-02), HFPS technology allows for a smooth and more stable output voltage compared to the voltage peaks and valleys which can occur with a conventional T/R set. This improvement in ESP field voltage stability is expected to result in additional decreases in filterable PM emissions from each unit.

Entergy requests that this sentence be rephrased as follows in the final permit.

> "However, Entergy anticipates no increase in filterable particulate matter as measured by EPA Reference Method 5."

Response to Comment

The requested language change has been made.

Comment #6

Emission Summary Table - Page 7: The total allowable emissions (lb/hr and tpy) appear to reflect the total permitted emissions from both the coal-fired and No. 2 fuel oil or biodiesel-fired operating scenarios for Unit 1 and Unit 2. As each of these scenarios is permitted for year-round operation, only the emissions from the higher-emitting scenario for each pollutant should be included in the plant-wide total allowable emissions value. This is consistent with the manner in which the total allowable emissions are presented in the current (R7) permit for the site. An example of these changes reflected in the format of the emission summary table is included in Attachment A to this letter. The totals included in Attachment A were calculated by summing the individual source emission limits, for each pollutant. For the HAP emission values, the total was rounded up to the nearest hundredth consistent with the formatting of the draft permit.

Response to Comment

The Emission Summary table has been updated.

Comment #7

Emission Summary Table - Page 11: The emission rates included in the summary table for SN-06C do not match the rates submitted for this source in the permit application, as supplemented via email on November 7, 2013. The total allowable emissions for SN-06C should be 129.9 lb/hr and 260.0 tpy PM, and 37.6 lb/hr and 90.1 tpy for PM_{10}. These values match the revised emission rate table (ERT) which was submitted for SN-06C during the application process.

Response to Comment

This comment should have also mentioned that there were two separate emails requesting to change the emission limits for SN-06C due to the change in the AP-42 equation for estimating road emissions. The first email was submitted on 11/7/2014. Specific Condition #74 was revised to match the provided ERT and calculations. ADEQ was unaware that the changes that had been made to update the limits in the Emission Summary Table were not preserved prior to the issuance of the draft. The second email was submitted on 12/10/2013 to correct a technical error with the calculations submitted on 11/7/2014. The overall result is a decrease in permitted limits. Both the Emission Summary Table and Specific Condition #74 limits have been corrected to reflect the information submitted and reviewed as part of the draft permitting decision.

Comment #8

Permit History - Page 15: Entergy notes that no summary of the R7 permit was added to the permit history section. ADEQ typically summarizes the changes from the previous permitting action with each subsequent permit issuance. A summary of the R7 permit action is requested to be added in keeping with this typical ADEQ practice.

Response to Comment

A summary of the changes made with the R7 permit has been included in the permit history.

Comment #9

Multiple Specific and Plantwide Conditions: A number of Specific Conditions and Plantwide Conditions in the draft permit contain a value of "Error! Reference Source not found" in place of a reference to General Provision 7. These error messages are requested to be replaced with references to General Provision 7 in the following conditions:

Specific Conditions: 4, 5, 12, 13, 17, 19, 27, 85, 92, 94, 98, 103, 110, 127 (first instance), 134, and 130, and Plantwide Condition: 16

Response to Comment

The noted error messages have been addressed to correctly reference GP7, where applicable.

Comment #10

Specific Condition 4 - Page 9: This condition establishes the compliance demonstration mechanism for the SO_2 limits of Specific Conditions 1 and 3. The compliance mechanism for the lb/hr limits of Specific Condition 1 is established as the arithmetic average of three one-hour periods of SO_2 emissions as measured by the CEMS and converted to pounds per hour per 40 CFR Part 75.

40 C.F.R. Part 75 establishes monitoring requirements for the acid rain mass emissions trading program. This program requires that substituted data be utilized to fill in any gaps in a facility's monitoring data. This substituted data represents an estimate of the emissions likely to have occurred from the unit during periods of missing and/or invalid CEMS data. When Part 75 monitoring data is used for the purposes of demonstrating compliance with a shorter-term emission limit, such as the lb/hr limits of Specific Condition #1, substituted data is not typically utilized. For example, see §60.334(b)(3)(iii) of NSPS Subpart GG. Similar examples exist in other NSPS subparts where EPA allows the use of Part 75 CEMS data for Part 60 compliance

purposes. ADEQ appears to have previously endorsed this position in Specific Conditions 12 and 13 which establish compliance demonstration requirements for SN-01 and SN-02 Operating Scenario II.

Entergy requests that the following sentence from Specific Condition 12 be added as the fourth sentence of Specific Condition 4.

> "Data Substituted in accordance with 40 CFR Part 75 for missing and/or invalid data will not be used for compliance with Specific Condition #1."

Response to Comment

The requested sentence has been added.

Comment #11

Specific Condition 5 - Page 19: For the same reasons outlined above, Entergy requests that the following sentence be added as the fourth sentence of Specific Condition 5.

> "Data substituted in accordance with 40 CFR Part 75 for missing and/or invalid data will not be used for compliance with Specific Condition #1."

Response to Comment

The requested sentence has been added.

Comment #12

Specific Condition 8 - Page 21: Entergy requests that the final sentence of this condition be revised to clarify that the quarterly excess emissions and monitoring system performance reports may be submitted to the Department via email. The ADEQ air enforcement branch currently accepts these reports electronically via email to airsubmission@adeq.state.ar.us, but the language in SC 8 is not clear that such electronic submission is acceptable. The final sentence of SC 8 is requested to be revised to read as follows:

> "Reports shall be submitted via email to airsubmission@adeq.state.ar.us or sent to the following address:"

Response to Comment

The requested change has been made.

Comment #13

Specific Condition 15 - Page 23: The final sentence of this condition should be revised to reference General Provision 17 consistent with the current (R7) permit for the facility.

Response to Comment

The requested change has been made.

Comment #14

Specific Conditions 24 and 25 - Page 24: The Plantwide Condition references in each of these conditions should be revised to reference Plantwide Condition 3 consistent with the current (R7) permit for the facility.

Response to Comment

The requested change has been made.

Comment #15

Specific Condition 28, Page 27: The cross-reference in the final sentence of Specific Condition 28 is requested to be revised to reference Specific Condition 7. This sentence referenced Specific Condition 7 in the R6 permit for the site and it appears that the Specific Condition 7 reference may have inadvertently been revised by ADEQ to a General Provision 7 reference in preparing the R7 permit. As Specific Condition 7 sets forth specific reporting requirements for opacity exceedances, this reference is appropriate. This change is consistent with the cross-reference in the equivalent language within the current Title V permit for Entergy's Independence Plant. See Specific Condition 3 of ADEQ permit 0449-AOP-R7.

Response to Comment

The requested change has been made.

Comment #16

Specific Condition 34(c)(iv) - Page 31: This condition was drafted by ADEQ as proposed by Entergy in the permit application. However, upon further review, Entergy requests that the phrase "... for an existing EGU..." be deleted from the final sentence of this condition for clarity. This language is unnecessary as both SN-01 and SN-02 are existing EGUs.

Response to Comment

The requested change has been made.

Comment #17

Specific Condition 50 - Page 38: The reference to Specific Condition #2 in this condition is requested to be updated to reference Specific Condition #30 which contains the applicability date for the MATS requirements.

Response to Comment

The requested change has been made.

Comment #18

Specific Condition 51 - Page 38: The reference to Specific Condition #2 in this condition is requested to be updated to reference Specific Condition #30 which contains the applicability date for the MATS requirements.

Response to Comment

The requested change has been made.

Comment #19

Specific Condition 53 - Page 38: This condition was drafted by ADEQ as proposed by Entergy in the permit application. However, upon further review this condition, while it arises from a different provision of Subpart UUUUU, is substantially duplicative of Specific Condition 43. To eliminate redundancy in the proposed conditions, Entergy requests that SC 53 be deleted and an additional regulatory reference to 40 CFR 63.10011(e) be added to SC 43.

Response to Comment

Specific Condition #53 was revised to RESERVED. The regulatory reference to 40 C.F.R. Part 63.10011(e) has been added to Specific Condition 43.

Comment #20

Specific Condition 55 - Page 39: This condition was drafted by ADEQ as proposed by Entergy in the permit application. However, upon further review this condition, while it arises from a different provision of Subpart UUUUU, is substantially duplicative of Specific Condition 42. To eliminate redundancy in the proposed conditions, Entergy requests that SC 55 be deleted and an additional regulatory reference to 40 CFR 63.10011(g) be added to SC 42.

Response to Comment

Specific Condition #55 was revised to RESERVED. The regulatory reference to 40 C.F.R. Part 63.10011(g) has been added to Specific Condition 42.

Comment #21

Specific Condition 74 Page 49: The PM emission limits for SN-06C are requested to be revised to 129.9 lb/hr and 260.0 tpy consistent with the emission rate table submitted to ADEQ for this source during the permit review process.

Response to Comment

The requested change has been made. See response to Comment #7.

Comment #22

18. Specific Condition 90 - Page 52: For clarity and consistency with the remainder of the condition, the definition of the term "TASH" is requested to be revised as follows:

> "TASH = monthly tons of fly ash disposed in the on-site landfill"

Response to Comment #

The requested change has been made.

Comment #23

19. Specific Condition 127 - Page 63: To correct the cross-reference error messages in the draft permit, the final sentence of this condition is requested to be revised to read as follows, consistent with the current (R7) permit for the site.

> "Construction of an alternate haul road shall comply with Plantwide Conditions #1 and #2."

Response to Comment

The requested change has been made.

Comment #24

Plantwide Condition 17 - Page 75: This condition is requested to be deleted from the permit. The draft R8 permit has been issued by ADEQ in response to the permit application referenced by this condition. As such, Entergy has satisfied this condition and it is no longer necessary.

Response to Comment

The requested change has been made.

Comment #25

Statement of Basis - Section 10: The regulatory applicability table in this section is requested to be revised to note the applicability of 40 CFR Part 63 Subpart UUUUU to SN-01 and SN-02.

Response to Comment

The requested change has been made.

Comment #26

Statement of Basis - Section 12(a): The text of Section 12(a) of the Statement of Basis (SOB) is requested to be revised to read as follows, "As acknowledged by ADEQ in Section 8(b) of the SOB, Entergy received a determination from ADEQ on February 19, 2013 that no permit or pre-authorization was required for the construction associated with the proposed pollution control project. As NAAQS review, when required, is a function of preconstruction permitting programs stemming from Title I of the Clean Air Act, and no such preconstruction permit approval was required for this project, no NAAQS review was required for this permitting action."

This permitting action did not involve the construction of any new emission units nor the modification of any existing emission units as that term is defined in Chapter 2 of ADEQ Regulation 19. As such, no NAAQS review was required.

Response to Comment

The permit decision does change the previously issued and effective permit. However, the changes involved in this action are not a "modification" as that term is defined at APC&EC Regulation 19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable. The section of the SOB has been changed to:

> This permit decision did not involve an emission increase over previously permitted rates; therefore a NAAQS evaluation is not required.

See Response to Comment #2.

Comment #27

The commenter submitted their comment to the email address provided in the public notice. The email reads as follows:

> *Allowing the coal-fired White Bluff power plant to increase its particle emissions is absolutely the WRONG thing to do! Think of all the increased health problems that this proposal would cause; that would not be in the best interests of people who live in the surrounding area of this plant. Please vote down this proposal!*
>
> *Chester A. Sautter*

Response to Comment

No specifics were provided with this comment. The commenter's opposition to the proposed modification has been noted.

The following written comments were received at the hearing held in Redfield, AR on August 14, 2014.

Comment #28 (Oral and Written)

Ms. Barbara Jarvis submitted the following written comments:

a. Economic implications: All fossil fuels are natural resources of the planet Earth. They are finite and exhaustible, unsustainable. Natural resources are capital, and we're spending them like [*TEXT ILLEGIBLE*]. This business is financially unsustainable.

b. Job security: coal jobs have declined. In [*TEXT ILLEGIBLE*] KY and VA employed 79,000 people; in 2012 they employed 41,000. The coal production remained steady, but the mining companies cut 38,000 jobs, replacing human beings with gigantic machines and technology. Coal jobs will continue to decline, but in 2013 the solar industry employed 142,698. 142,000 + compared to 89,000 jobs in coal.

c. "Clean Coal?" It will take 10-40% of the electricity produced by coal to "sequester" its carbon emissions will [*TEXT ILLEGIBLE*] 3,000 to 7,000 deaths, and millions in healthcare.

Response to Comment

The commenter's concerns have been noted. These comments, however, do not pertain to the permit modification. These comments do not request a change to the permit.

Comment #29 (Oral and Written)

Mr. Glenn Hooks is concerned about increased particulate matter and related health effects. The commenter references a Sierra Club analysis of the modification that estimated the proposed modification will result in an estimated 22 tons/yr of particulate matter emissions at the plant.

The commenter does not want the requested permit modifications approved unless ADEQ determines "either through modeling or otherwise" that the modification will not result in violation of any EPA air quality standard. The commenter mentioned that several provisions of Federal and Arkansas law require ADEQ to perform an air quality analysis before it approves a permit. The commenter understands that historically, ADEQ has used the Title V permitting process to assess a plant's emissions impact on EPA air quality, and with this permitting action ADEQ did not. The commenter states that ADEQ must develop another process for ensuring that the plant does not violate air quality standards.

The commenter concludes that the White Bluff plant is nearing the end of its useful lifecycle, and that it is time to consider replacing the plant with cleaner options as an alternative to spending the money in retrofits and upgrades.

Response to Comment

As to Mr. Hooks' comment regarding a NAAQS evaluation, the changes involved in this action are not a "modification" as that term is defined at APC&EC19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable.

The primary NAAQS are designed to protect human health. This permit contains limits and conditions that are protective of human health and the environment.

As to Mr. Hooks' comment regarding the useful life of the White Bluff plant, the commenter's concerns have been noted. However, the comment does not request a specific change to the permit.

See Response to Comment #2.

Comment #30

The draft White Bluff permit cannot lawfully be issued because no adequate determination has been made that the modified White Bluff plant will not violate a NAAQS.

Response to Comment

The permit decision does change the previously issued and effective permit. However, the changes involved in this action are not a "modification" as that term is defined at APC&EC Regulation 19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable.

See Response to Comment #2.

Comment #31

The draft White Bluff permit cannot lawfully be issued because the modified White Bluff plant will violate applicable requirements of Arkansas law that protect public health.

Response to Comment

This comment is vague and does not cite to any specific Arkansas regulation or statute. However, the primary NAAQS are designed to protect human health. This permit contains limits and conditions that are protective of human health and the environment. Additionally, the changes involved in this action are not a "modification" as that term is defined at APC&EC Regulation 19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable.

See Response to Comment #2.

Comment #32

Entergy's emissions estimates are unreliable and unverifiable.

The analysis Entergy performed to predict emissions from the modified White Bluff plant is almost entirely unreviewable and unverifiable because of a failure to provide necessary inputs and assumptions. As Dr. Sahu explains ADEQ has no basis to rely on Entergy's emissions estimates:

> In any analysis provided in a regulatory context, it is critically important that the entity performing the analysis provide all inputs and assumptions used so that the regulatory agency and others may assess the reliability and accuracy of the analysis. The New Source Review (NSR) analysis provided by Entergy to support the ACI project fails to meet this standard. Its work is almost entirely unreviewable and unverifiable because of a failure to provide support for the necessary inputs and assumptions or, in some cases, the inputs and assumptions themselves.

Supplement Report of Dr. Ranajit Sahu at 1 (Exhibit 1).

In his preliminary report that Sierra Club attached to its July 11, 2014 comments on the Draft White Bluff Permit, Dr. Sahu noted five critical flaws in Entergy's technical support for its claimed reduction in PM emissions from the ACI project:

- First, Entergy provides no details on the basic design parameters of the electrostatic precipitators ("ESPs") at White Bluff Units 1 and 2. This information is critical to any review regarding the performance of the ESPs with ACI addition at the White Bluff Plant. Sahu Preliminary Report at 1-2.6

- Second, Entergy does not state how much ACI (or which type) will be used in order to reduce mercury emissions to below the Mercury and Air Toxics Standards ("MATS") levels. In fact, no mercury testing data is provided at all. Thus, there is no data to show that a specific ACI process would lead to the necessary mercury reductions. Obviously, ACI runs that do not achieve the MATS-required mercury reductions are useless for assessing PM emissions since Entergy must comply with the MATS requirements for mercury. Sahu Preliminary Report at 2.

- Third, the June 2012 tests on Unit 1 are unreliable because the gas flow rates indicate that Unit 1 was running at a much reduced capacity during these tests thereby invalidating the tests' usefulness to predict emissions at full capacity. In addition, Unit 2 operates at much higher heat input rates than Unit 1 and thus Entergy's attempt to extrapolate results from Unit 1 to Unit 2 is not reasonable. Sahu Preliminary Report at 2

- Fourth, Entergy's failure to reasonably determine baseline PM emissions undermines its prediction of an emissions decrease. The identified wide range of possible PM baselines indicates that PM emission could increase, even under Entergy's flawed analysis. Sahu Preliminary Report at 3.

- Fifth, the Energy & Environmental Research Center tests provided by Entergy are not reliable because they were performed at an entirely different ESP, with different design parameters, and with no showing that these results could be achieved at the White Bluff ESPs. Sahu Preliminary Report at 3-6.

In his supplemental report attached to these comments, Dr. Sahu notes two additional flaws in Entergy's analysis:

- First, Entergy has not provided the inputs and assumptions used in the Aurora model that the company used to estimate projected futures estimates of emissions of all relevant pollutants. Entergy used this model to create projected heat input figures for Units 1 and 2. These heat input figures were then used by Entergy for all of its future emissions calculations. Without the inputs and assumptions used to generate the heat input figures, the emissions calculations themselves are not verifiable or even understandable. Sahu Supplemental Report at 1.

- Second, for a given future year, Entergy has adjusted (by roughly 5%) the Aurora projected heat input estimate to account for a "discrepancy" between how Entergy reports heat input to the U.S. EPA Clean Air Markets Division versus what Entergy believes the "accurate" heat input figure should be. In any case, in order to make this adjustment, Entergy states that it derived purportedly more accurate heat input numbers from fuel usage at each White Bluff unit and the heating value of the fuel(s). But Entergy provides only its final heat input values without any data to support the fuel usage and heating value inputs. Nor does Entergy provide any discussion as to why the heat input calculated from these parameters would be more accurate than the figures reported to the U.S. EPA. Sahu Preliminary Report at 1-2.

For all of these reasons, ADEQ has no reasonable basis for which to rely on Entergy's emissions estimates. There is therefore no demonstration in the permitting record that the modified White Bluff Plant will not violate federal or Arkansas air quality requirements. Without such an analysis, ADEQ cannot lawfully issue the modified White Bluff permit.

Response to Comment

No changes to the permit have been made.

PSD regulations allow a source to compare "baseline actual emissions" with "projected actual emissions". Entergy submitted emission projections showing that the project will not result in a significant emissions increase for any pollutant using the methods described in PSD regulations for calculating whether there is significant emissions increase.

The following oral comments were received at the hearing held in Redfield, AR on August 14, 2014.

Comment #33 (Oral)

Tony Mendoza with Sierra Club submitted written comments at the public hearing. He made two additional points via oral comments. Those comments were:

1. Mr. Mendoza understands that ADEQ hands are tied regarding the air quality modeling and Act 1302. He appreciates the other modeling ADEQ is doing in another process to ensure that air quality is protected for all citizens in Arkansas.
2. He urged the Department to consider the findings of Dr. Sahu's report regarding the increase in particulate matter from the ACI project.

Response to Comments

The first item raises no issue that requires a response. As to the second item, see Response to Comment #1.

Comment #34 (Oral)

The commenter stated that Pulaski County is already skirting the EPA regulations regarding PM and the proposed modification may well increase the PM load in Pulaski County and result in non-compliance with EPA standards. The commenter then reminded everyone that coal-fired power plants make cheap electricity but also increases pollution. The commenter stated that PM_{10} dangerous to people with lung conditions and their life span is shortened every time pollution is increased. The commenter then posed the question, "Is it right that we take away their life to have comfortable electricity for ourselves?"

Response to Comment

The commenter's concerns have been noted. However, the comment does not request a specific change to the permit.

As to the issue of PM, the addition of ACI is not anticipated to increase any emissions from the boilers. There may be a small increase in actual (versus permitted) road emissions from delivery of ACI but the cumulative impact on Pulaski County Attainment status will be trivial. Based on Entergy's analysis, overall emissions of PM will decrease.

Comment #35 (Oral)

The commenter was concerned about the fine PM. The commenter understood that Pulaski County is close to exceeding the EPA standards for safe levels for PM and that according to Sierra Club's report, the Entergy permit modification project could cause the PM standard to be exceeded. The commenter states that PSD could have an impact on Pulaski County and urged consideration of that. The commenter was concerned that Entergy is self-policing in determining the impacts from the modification. According to the commenter, that is very dangerous, and the very reason why ADEQ and EPA exist is so that companies do not self-regulate. The commenter requested that the Department consider all information available and not just what Entergy may be saying for their own vested interest. The commenter then states that federal and state law require that ADEQ perform an Air Quality analysis before approving a permit and asked, "Is Act 1302 in violation of those existing laws?"

Response to Comment

The comment raises several distinct issues. The Department's responses to those issues are as follows:

- The addition of ACI is not anticipated to increase any emissions from the boilers. Any increase in road emissions from delivery of ACI will have a trivial impact on Pulaski County Attainment status.

- The permit contains necessary compliance mechanisms. No specific issues were identified by the commenter regarding this issue.

- As to the issue of conducting at air quality analysis, the changes involved in this action are not a "modification" as that term is defined at APC&EC Regulation 19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable.

Comment #36 (Oral)

The commenter makes a number of statements that are generally for the continued use of coal.

Response to Comment

None of these statements directly refer to the proposed permit modifications at hand.

Comment #37 (Oral)

The commenter makes a number of statements in support of Entergy.

Response to Comment

None of these statements directly refer to the proposed permit modifications at hand.

Comment #38 (Oral)

The commenter makes statements supporting replacement of coal with renewable sources. The commenter understands that mercury causes health effects. The commenter is against ADEQ approving this modification with particulate emissions remaining the same or increasing. The commenter does not believe there is evidence the modification will be effective.

Response to Comment

The use of coal as a fuel source versus the use of renewables as a fuel source for the White Bluff plant is not an issue relevant to this permit modification. No specifics are presented by the commenter in the other issues presented.

Comment #39 (Oral and Written)

Ms. Shelley Buonaiuto submitted the following written comment:

The proposed modifications to the White Bluff Coal Plant to reduce mercury and some other toxic emissions are determined by a study by the Sierra Club to actually cause the increase of some fine PM by some 22 tons.

Pulaski County is close to exceeding EPA standards for safe levels of PM, so this extra could cause significant increase in cases of asthma and other respiratory illnesses, and heart disease.

ADEQ must conduct an independent air quality analysis before any permit for the proposed modification to White Bluff is approved.

Even if proper scrubbers could be added, those wouldn't prevent CO_2 emissions. The only thing I know of that is studied that could possibly contain CO_2 is carbon sequestration, which technology is not yet proven to be possible, efficient, safe, or financially viable.

Since White Bluff is already so old, dirty and close to retirement, it would make more sense to close the plant. This would make it easier to meet the proposed EPA regulation according to section 111d of the Clean Air Act, to reduce CO_2 emissions in AR by 44%.

Rather than spending money on a plant so close to retirement, money should be spent to provide transmission lines for the Integra natural gas plant, so it could operate at capacity.

The EPA regulations are already possibly too little, too late. There are methane releases from the Arctic Ocean 10 times the usual amount. In Siberia, huge holes are suddenly appearing. They've been flying helicopters down them theorized to be sudden releases of methane from under thawing permafrost. The Planet's climate is threatened by a feedback loop that would cause irreversible (at least within the next few hundred to a thousand years) accumulation of GHGs in the atmosphere causing heat to rise more than the 2% C decreed by NASA. Oceans would rise from 4-12 or more feet, inundating our coasts and islands, not to mention the other extreme weather events due to climate change.

Yes regulations will cause utility prices to rise. This could be remedied by the enactment of a state or national, or both, carbon fee and dividend, with 100% of the fee collect returned to the consumer. This would cushion the economy from negative impacts. It would also provide reliable price points for investment in renewables.

But for now what is immediately needed is an independent air quality analysis, performed by the ADEQ, before any ill advised permit is approved. The ADEQ is already involved in a law suit due to the permit granted to the Cargill and C&H Hog farm without the necessary analysis of impacts on the Buffalo River, or proper notification of those affected. We need to ADEQ to protect our air and water quality and our health. You are the government agency we depend on for this.

The commenter did not know about Act 1302 prior to the public meeting understands ADEQ has to comply with Act 1302. There must be some kind of mechanism that allows ADEQ to conduct an independent air quality analysis before any permit for the proposed modifications is approved. Entergy's analysis should not be trusted.

Response to Comment

The commenter raises multiple issues. The Department's responses to those issues are as follows:

The addition of ACI is not anticipated to increase any emissions from the boilers. Any increase in road emissions from delivery of ACI will have a trivial impact on Pulaski County Attainment status.

- The comments on CO_2 and its impact on the environment are noted. However, CO_2 is not at issue in this permit modification.

- Alternatives to this facility (such as the Union Power- Entegra natural gas combined cycle plant) are not at issue in this permit modification.

- As to the issue of conducting an air quality analysis, the changes involved in this action are not a "modification" as that term is defined at APC&EC Regulation 19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable.

Comment #40 (Oral)

The commenter makes a number of statements in support of Entergy. The commenter first contends that the MATS control system being installed will allow the plant to be compliant with state and federal regulations. The commenter supports the permit request. The commenter has not had any health effects related to the air quality around the facility. The commenter is against closing the plant and displacing hundreds of people from their jobs.

Response to Comment

The commenter's support for Entergy is noted.

Comment #41 (Oral)

The commenter does not want to take the risk of exceeding safe levels of PM (particulate matter) and supports transitioning to clean power. The commenter supports solar energy. According to the commenter, there are laws that require ADEQ to perform air quality analysis before approving a permit and consider alternatives.

Response to Comment

The use of solar energy as fuel source is not an issue relevant to this permit modification. As to the issue of conducting an air quality analysis, the changes involved in this action are not a "modification" as that term is defined at APC&EC Regulation 19, Chapter 2. This permitting action does not increase federally regulated air pollutants over rates that were previously permitted. Therefore the requirement contained in the Arkansas SIP regarding a demonstration that proposed emissions will not interfere with attainment or maintenance of NAAQS is not applicable.

CERTIFICATE OF SERVICE

I, Cynthia Hook , hereby certify that a copy of this permit has been mailed by first class mail to Entergy Arkansas, Inc. (White Bluff Plant), 1100 White Bluff Road, Redfield, AR, 72132, on this 22nd day of January, 2015.

C Hook

Cynthia Hook , ASIII, Air Division