ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2004–0490, FRL–8033–4]

RIN 2060–AM79

Standards of Performance for Stationary Combustion Turbines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action promulgates standards of performance for new stationary combustion turbines in 40 CFR part 60, subpart KKKK. The standards reflect changes in nitrogen oxides (NO_X) emission control technologies and turbine design since standards for these units were originally promulgated in 40 CFR part 60, subpart GG. The NO_X and sulfur dioxide (SO_2) standards have been established at a level which brings the emissions limits up to date with the performance of current combustion turbines.

DATES: *Effective date:* The final rule is effective July 6, 2006. The incorporation by reference of certain publications in the final rule is approved by the Director of the Office of the Federal Register as of July 6, 2006.

ADDRESSES: *Docket:* EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2004–0490. All documents in the docket are listed electronically on *www.regulations.gov.* Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy at the Air and Radiation Docket, Docket ID No. EPA–HQ–OAR–2004–0490, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air and Radiation Docket Center is (202) 566–1742.

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SUPPLEMENTARY INFORMATION:

Regulated Entities. Categories and entities potentially regulated by this action are those that own and operate stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (GJ) (10 million British thermal units (MMBtu)) per hour that commenced construction, modification, or reconstruction after February 18, 2005. Regulated categories and entities include, but are not limited to:

Category	NAICS	SIC	Examples of regulated entities
Any industry using a new stationary combustion turbine as defined in the final rule	2211	4911	Electric services.
	486210	4922	Natural gas transmission.
	211111	1311	Crude petroleum and natural gas.
	211112	1321	Natural gas liquids.
	221	4931	Electric and other services, combined.

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of the final rule is available on the WWW through the Technology Transfer Network Website (TTN Web). Following signature, EPA will post a copy of the final rule on the TTN's policy and guidance page for newly proposed or promulgated rules at *http://www.epa.gov/ttn/oarpg.* The TTN provides information and technology exchange in various areas of air pollution control.

Judicial Review. Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of the final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia by September 5, 2006. Under section 307(d)(7)(B) of the CAA, only an objection to the final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by today's final action may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

Section 307(d)(7)(B) of the CAA further provides that ''only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review.'' This section also provides a mechanism for EPA to convene a proceeding for reconsideration, ''if the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to EPA should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460, with a copy to both the person(s) listed in the **FOR FURTHER INFORMATION CONTACT** section, and the Director of the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave., NW., Washington, DC 20004.

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

I. Background

This action promulgates new source performance standards (NSPS) that apply to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 GJ (10 MMBtu) per hour, based on the higher heating value (HHV) of the fuel, that commence construction, modification, or reconstruction after February 18, 2005. The NSPS are being promulgated pursuant to section 111 of the CAA, which requires EPA to promulgate and periodically revise the NSPS, taking into consideration available control technologies and the costs of control. EPA promulgated the original NSPS for stationary gas turbines in 1979 (44 FR 52798). Since promulgation of the NSPS for stationary gas turbines, many advances in the design and control of emissions from stationary combustion turbines have occurred. Nitrogen oxides and SO_2 are known to cause adverse health and environmental effects. The final rule represents reductions in the NO_X and SO_2 limits of over 80 and 90 percent, respectively. Today's action allows turbine owners and operators to meet either concentration-based or output-based standards. The output-based standards in the final rule allow owners and operators the flexibility to meet their emission limit targets by increasing the efficiency of their turbines.

II. Summary of the Final Rule

A. Does the final rule apply to me?

Today's final rule applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 GJ (10 MMBtu) per hour that commence construction, modification, or reconstruction after February 18, 2005. A stationary combustion turbine is defined as all equipment, including but not limited to the combustion turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. The applicability of the final rule is similar to that of 40 CFR part 60, subpart GG, except that the final rule applies to new, modified, and reconstructed stationary combustion turbines, and their associated heat recovery steam generators (HRSG) and duct burners. The stationary combustion turbines subject to subpart KKKK, 40 CFR part 60, are exempt from the requirements of 40 CFR part 60, subpart GG. Heat recovery steam generators and duct burners subject to subpart KKKK are exempt from the requirements of 40 CFR part 60, subparts Da, Db, and Dc.

B. What pollutants are regulated?

The pollutants that are regulated by the final rule are NO_X and SO_2.

C. What is the affected source?

The affected source for the stationary combustion turbine NSPS is each stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 GJ (10 MMBtu) per hour that commences construction, modification, or reconstruction after February 18, 2005. Integrated gasification combined cycle (IGCC) combustion turbine facilities covered by subpart Da of 40 CFR part 60 (the Utility Boiler NSPS) are exempt from the requirements of the final rule. Combustion turbine test cells/stands are also exempt from the requirements of the final rule.

D. What emission limits must I meet?

The standards for NO_X in the final rule allow the turbine owner or operator the choice of a concentration-based or output-based emission standard. The concentration-based limit is in units of parts per million by volume (ppmv) at 15 percent oxygen. The output-based emission limit is in units of emissions mass per unit useful recovered energy, nanograms per Joule (ng/J) or pounds per megawatt-hour (lb/MWh). The NO_X limits, which are presented in table 1 of this preamble, differ based on the fuel input at peak load, fuel, application, and location of the turbine. The fuel input of the turbine does not include any supplemental fuel input to the heat recovery system and refers to the rating of the combustion turbine itself. The 50 MMBtu/h category peak heat input is based on the fuel input to a 23 percent efficient 3.5 megawatt (MW) combustion turbine. The 850 MMBtu/h category peak heat input is based on the fuel input to a 44 percent efficient 110 MW combustion turbine. The 30 MW category for turbines located north of the Arctic Circle, turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbines operating at temperatures less than 0°F is based on the categories in the original NSPS for combustion turbines, subpart GG.

TABLE 1.—NO_X EMISSION STANDARDS

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing natural gas, electric generating.	≤ 50 million British thermal units per hour(MMBtu/h).	42 ppm at 15 percent oxygen (O_2) or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas.	> 850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh).
New turbine firing fuels other than natural gas, electric generating.	≤ 50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).

TABLE 1.—NO_X EMISSION STANDARDS—Continued

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing fuels other than natural gas, mechanical drive.	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas.	> 850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas.	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas.	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbines operating at temperatures less than 0 °F.	≤ 30 megawatt (MW) output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbines operating at temperatures less than 0 °F.	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine.	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

We have determined that it is appropriate to exempt emergency combustion turbines from the NO_X limit. We have defined these units as turbines that operate in emergency situations. For example, turbines used to supply electric power when the local utility service is interrupted are considered to fall under this definition. Stationary combustion turbine test cells/stands are also exempt from the final rule. Combustion turbines used by manufacturers in research and development of equipment for both combustion turbine emissions control techniques and combustion turbine efficiency improvements are exempt from the NO_X limits on a case-by-case basis. Given the small number of turbines that are expected to fall under this category and since there is not one definition that can provide an all-inclusive description of the type of research and development work that qualifies for the exemption from the NO_X limit, we have decided that it is appropriate to make these exemption determinations on a case-by-case basis only.

The emission standard for SO_2 is the same for all turbines regardless of size and fuel type. You may not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 ng/J (0.90 lb/MWh) gross energy output for turbines that are located in continental areas, and 780 ng/J (6.2 lb/MWh) gross energy output for turbines located in noncontinental areas. You can choose to comply with the SO_2 limit itself or with a limit on the sulfur content of the fuel. The fuel sulfur content limit is 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for turbines located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input in noncontinental areas. This is approximately equivalent to 0.05 percent by weight (500 parts per million by weight (ppmw)) fuel oil and 0.4 percent by weight (4,000 ppmw) fuel oil respectively.

E. If I modify or reconstruct my existing turbine, does the final rule apply to me?

The final rule applies to stationary combustion turbines that are modified or reconstructed after February 18, 2005. The methods for determining whether a source is modified or reconstructed are provided in 40 CFR 60.14 and 40 CFR 60.15, respectively. A turbine that is overhauled as part of a maintenance program is not considered a modification if there is no increase in emissions.

F. How do I demonstrate compliance?

In order to demonstrate compliance with the NO_X limit, an initial performance test is required. If you are using water or steam injection, you must continuously monitor your water or steam to fuel ratio in order to demonstrate compliance and you are not required to perform annual stack testing to demonstrate compliance. If you are not using water or steam injection, you must conduct performance tests annually following the initial performance test in order to demonstrate compliance. Alternatively, you may choose to demonstrate continuous compliance with the use of a continuous emission monitoring system (CEMS) or parametric monitoring; if you choose this option, you are not required to conduct subsequent annual performance tests.

If you are using a NO_X CEMS, the initial performance test required under 40 CFR 60.8 may, alternatively, coincide with the relative accuracy test audit (RATA). If you choose this as your initial performance test, you must perform a minimum of nine reference method runs, with a minimum time per run of 21 minutes, at a single load level, within 75 percent of peak (or the highest achievable) load. You must use the test data both to demonstrate compliance with the applicable NO_X emission limit and to provide the required reference method data for the RATA of the CEMS.

G. What monitoring requirements must I meet?

If you are using water or steam injection to control NO_X emissions, you must install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine. Alternatively, you could use a CEMS consisting of NO_X and O_2 or carbon dioxide (CO_2) monitors. During each full unit operating hour, each monitor must complete a minimum of one cycle of operation for each 15-minute quadrant of the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates.

If you operate any new turbine which does not use water or steam injection to control NO_X emissions, you must perform annual stack testing to demonstrate continuous compliance with the NO_X limit. Alternatively, you could elect either to use a NO_X CEMS or perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define appropriate parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously;

(2) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in the low NO_X combustion mode;

(3) For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls; and

(4) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in 40 CFR 75.19, the monitoring requirements of the turbine NSPS may be met by performing the parametric monitoring described in section 2.3 of appendix E of part 75 of this chapter or in 40 CFR 75.19(c)(1)(iv)(H).

Alternatively, you can petition the Administrator for other acceptable methods of monitoring your emissions. If you choose to use a CEMS or perform parameter monitoring to demonstrate continuous compliance, annual stack testing is not required.

If you choose to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test to establish acceptable operating ranges.

If you operate any stationary combustion turbine subject to the provisions of the final rule, and you choose not to comply with the SO_2 stack limit, you must monitor the total sulfur content of the fuel being fired in the turbine. There are several options for determining the frequency of fuel sampling, consistent with appendix D to part 75 of this chapter for fuel oil; the sulfur content must be determined and recorded once per unit operating day for gaseous fuel, unless a custom fuel sampling schedule is used. Alternatively, you could elect not to monitor the total potential sulfur emissions of the fuel combusted in the turbine, if you demonstrate that the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for turbines located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input in noncontinental areas. This demonstration may be performed by using the fuel quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract, or through representative fuel sampling data which show that the potential sulfur emissions of the fuel does not exceed the standard. Turbines located in continental areas can demonstrate compliance by burning fuel oil containing 500 parts per million (ppm) or less sulfur or natural gas containing 20 grains or less of sulfur per 100 standard cubic feet. Turbines located in noncontinental areas can demonstrate compliance by burning fuel oil containing 0.4 weight percent (4,000 ppm) sulfur or less or natural gas containing 140 grains or less of sulfur per 100 standard cubic feet.

If you are required to periodically determine the sulfur content of the fuel combusted in the turbine, a fuel sample must be collected during the performance test. For liquid fuels, the sample for the total sulfur content of the fuel must be analyzed using American Society of Testing and Materials (ASTM) methods D129–00 (Reapproved 2005), D1266–98 (Reapproved 2003), D1552–03, D2622–05, D4294–03, or D5453–05. For gaseous fuels, ASTM D1072–90 (Reapproved 1999); D3246–05; D4468–85 (Reapproved 2000); or D6667–04 must be used to analyze the total sulfur content of the fuel.

The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

H. What reports must I submit?

For each affected unit for which you continuously monitor parameters or emissions, or periodically determine the fuel sulfur content under the final rule, you must submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). For simple cycle turbines, excess emissions must be reported for all 4-hour rolling average periods of unit operation, including start-up, shutdown, and malfunctions where emissions exceed the allowable emission limit or where one or more of the monitored process or control parameters exceeds the acceptable range as determined in the monitoring plan. Combined cycle and combined heat and power units use a 30-day rolling average to determine excess emissions.

For each affected unit for which you perform an annual performance test, you must submit an annual written report of the results of each performance test.

III. Summary of Significant Changes Since Proposal

A. Applicability

The proposed rule applied to owners and operators of stationary combustion turbines with a peak power output at peak load equal to or greater than 1 MW. The final rule applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 GJ (10 MMBtu) per hour, based on the HHV of the fuel. Assuming an efficiency of 23 percent, the final rule applies to stationary combustion turbines with a peak output greater than 0.7 MW. Another change from the proposed rule is the addition of an exemption for stationary combustion turbine test cells/stands.

B. Emission Limitations

The proposed rule established four subcategories of turbines based on fuel type and turbine size, and different NO_X emission standards were proposed for each subcategory. The proposed subcategories were the following: Less than 30 MW and firing natural gas; greater than or equal to 30 MW and firing natural gas; less than 30 MW and firing oil or other fuel; and greater than or equal to 30 MW and firing oil or other fuel. The final rule has 14 subcategories, which are listed in table 1 of this preamble. Instead of the proposed size break at 30 MW, the final rule breaks the turbines into subcategories of less than or equal to 50 MMBtu/h of heat input, greater than 50 MMBtu/h heat input to less than or equal to 850 MMBtu/h heat input, and greater than 850 MMBtu/h heat input. Subcategories have been included for modified and reconstructed turbines, heat recovery units operating independent of the combustion turbine, turbines located north of the Arctic

Circle, and turbines operating at part load. EPA concluded that subcategories based on heat input at peak load rather than power output are more appropriate. The boiler NSPS standards are subcategorized by heat input, and heat input is a better indication than power output of available combustion controls. Basing categories on heat input also eliminates the disincentive of turbine redesign that increases efficiency and output, but not fuel consumption.

The proposed standards for NO_X were output-based limits in units of emissions mass per unit useful recovered energy, ng/J or lb/MWh. This format has been retained in the final rule; however, an optional concentration-based standard in units of ppmv at 15 percent O_2 has also been included for each subcategory.

The proposed SO_2 emission limits were raised slightly in the final rule, and an additional subcategory was created. Different emission limits were provided for turbines located in noncontinental areas; those turbines have an SO_2 emission limit of 780 ng/J (6.2 lb/MWh). The other difference from the proposed rule is that turbines located in Alaska do not have to meet the SO_2 emission limits until January 1, 2008.

C. Testing and Monitoring Procedures

The final rule contains several differences from the proposed testing and monitoring procedures. The performance test for NO_X is not required to be conducted at four load levels; in the final rule the test must be conducted at one load level that is within plus or minus 25 percent of 100 percent of peak load. Testing may be performed at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. We added a requirement that the ambient temperature be greater than 0 °F when the test is conducted. Similarly, we specified in the final rule that turbine owners and operators that are continuously monitoring parameters or emissions have an alternate limit during periods when the turbine operates at less than 75 percent of peak load or the ambient temperature is less than 0 °F.

A provision was added that allows owners and operators of stationary combustion turbines to reduce the frequency of subsequent NO_X performance tests to once every 2 years if the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine. If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, annual performance tests must be resumed.

The sulfur sampling requirements in the final rule also contain some differences from the proposed requirements. Acceptable custom schedules for determining the total sulfur content of gaseous fuels were added in the final rule. We removed the statement that was in the proposed rule that required at least one fuel sample to be collected during each load condition, since we are no longer requiring performance tests to be conducted at multiple loads.

Finally, the proposed rule required that diffusion flame turbines without SCR controls continuously monitor at least four parameters indicative of the unit's NO_X formation characteristics; the final rule does not specify a minimum number of parameters that must be continuously monitored by these units.

D. Reporting

The reporting requirements in the final rule contain two differences from the proposed reporting requirements. The proposed 40 CFR 60.4395 said that reports should be postmarked by the 30th day following the end of each calendar quarter. The proposed rule actually required semiannual reports, therefore, that section should have read that the reports should be postmarked by the end of each 6-month period, and the final rule has been written to correct this error. Also, we specified that turbines that are conducting annual performance testing should submit annual reports with the results of the performance testing.

E. Other

Several modifications were made to the definitions in the proposed rule. The definition of efficiency was clarified to indicate that it is based on the HHV of the fuel. The definitions for lean premix stationary combustion turbine and diffusion flame stationary combustion turbine were modified to alleviate any potential ambiguity about which definition a turbine would fall under. Lastly, the definition of natural gas was revised to remove references to pipeline natural gas.

IV. Summary of Responses to Major Comments

A more detailed summary of comments and our responses can be found in the Response to Public Comments on Proposed Standards of Performance for Stationary Combustion Turbines document, which can be obtained from the docket.

A. Applicability

Comment: Several commenters suggested changing the minimum size threshold for applicability of the rule, as proposed. Some suggested 3 MW, while others suggested 3.5 MW. Reasons included the fact that lean premix technology is not available for turbines less than 3 MW, other control options are not feasible, no commercially available small units were identified that can achieve the proposed emission levels, and no emission test data were provided in the docket for small units.

Another reason given was that there was some ambiguity because of the differing minimum size criteria between the rule, as proposed, and 40 CFR part 60, subpart GG. Two commenters suggested that EPA clarify that subpart KKKK, 40 CFR part 60, is the effective NSPS, and that 40 CFR part 60, subpart GG, no longer applies for all new, reconstructed, or modified stationary combustion turbines. The commenters said that it is not clear if 40 CFR part 60, subpart GG, will no longer apply after the effective date of the final rule. Since the minimum size criterion was slightly different in the two subparts, the commenters requested clarification of this issue to avoid future confusion. The commenters requested that EPA clarify that 40 CFR part 60, subpart GG, no longer applies after the effective date of the final rule.

Response: This comment addresses the minimum size threshold for the final rule. In 40 CFR 60.4305 of the rule, as proposed, the applicability criteria stated that the applicable units are turbines with a peak load power output equal to or greater than 1 MW. This minimum size threshold is marginally higher than the minimum threshold in 40 CFR part 60, subpart GG, which affects turbines with a minimum heat input at peak load of 10.7 GJ per hour or larger based on the lower heating value of the fuel (approximately 10 MMBtu/h). With a lower heating value (LHV) thermal efficiency of 23 to 25 percent, which is typical at full load for older small industrial turbines, this firing rate is equivalent to 0.7 MW. While the difference between the 40 CFR part 60, subpart GG, and the proposed 40 CFR part 60, subpart KKKK, applicability thresholds was initially believed to be minor, the natural gas industry representatives pointed out that there is a class of turbines used in natural gas transmission that fall within this range. Solar Saturn units, which are widely used in the gas transmission industry, include a peak load between 0.7 and 1.0 MW. While the industry has said that not many new units are sold in this range, there are many already in existence, which may be modified or reconstructed, which would need to be addressed by one of the rules. Therefore, the final rule has been written to include the minimum size applicability threshold of 10.7 GJ per hour.

While we do not agree that the size cutoff should be established to exempt turbines less than 3.5 MW, EPA has concluded that it is appropriate to create a new subcategory. Discussions with turbine manufacturers suggest that a subcategory for small turbines, between the minimum size threshold for the final rule and 50 MMBtu/h (HHV), should be created. This division is based on the fuel input to a 23 percent efficient 3.5 MW turbine. The only turbine identifiable in this size range that can be used for mechanical drive applications is a Solar Saturn, and Solar Turbines does not plan to further develop dry low NO_X technology on the Saturn line, nor does it have that capability at the current time. According to the gas transmission industry representatives, there are about 300 turbines in this small size range, comprising over 25 percent of the existing turbines in gas transmission. None of these units include lean premixed combustion. Other add-on controls have not been applied to the variable load operating profile characteristic of gas transmission equipment, nor would such add-on controls be economically feasible for these small units with minimal emissions. Therefore, the final rule has incorporated a new subcategory of small turbines, ranging from the applicability limit to 50 MMBtu/h.

Comment: Several commenters suggested that modified and reconstructed units should be treated differently than new units. Reasons provided by the commenters included costs for retrofitting being excessive, and weight and space needs being prohibitive. One commenter stated that there are many existing turbines that could be affected by the modification section of the rule for which there is no cost effective technology that achieves emissions lower than those suggested by the commenter. One commenter stated that the terms ''modification'' and ''reconstruction'' were not clearly defined, and that requiring these units to meet the same limits as new units may discourage existing turbine users from modifying units to improve efficiency or lower emissions, if such modifications do not ensure compliance with the limit for new units.

Options recommended by the commenters included removing them from the applicability of 40 CFR part 60, subpart KKKK, giving them separate limits under subpart KKKK, or making them subject to 40 CFR part 60, subpart GG. One commenter recommended that units manufactured through 1985 (20 years and older) be exempted from the requirements of the proposed NSPS, and the previous NSPS levels should apply.

Response: We acknowledge the commenters' views, and in the final rule there are new subcategories for some modified and reconstructed units. While we provided more flexibility in the final rule for small and medium sized turbines (ranging from the applicability threshold to 850 MMBtu/h), we had no information on large turbines (greater than 850 MMBtu/h) which would suggest any compliance issues for modified or reconstructed units. Therefore, no subcategory was added for large (greater than 850 MMBtu/h) modified or reconstructed units.

Comment: Several commenters suggested that EPA include an exemption for offshore turbines, turbines located north of the Arctic Circle, and turbines in other existing remote locations. Alternatively, the commenters suggested subcategorizing them separately. The commenters said that due to a harsh environment and fuel availability and variability, these turbines are commonly diffusion flame, and land-based emissions abatement techniques are unsuitable; space limitations are also a concern. One commenter said that the rule, as proposed, would preclude the use of new, modified or reconstructed turbines located in electric utility service in Alaska, because of the additional costs associated with meeting the proposed limits.

Response: EPA has concluded that a subcategory should be created for modified and reconstructed offshore turbines and turbines installed north of the Arctic Circle to recognize their distinct differences. There is a substantial difference in temperature between the North Slope of Alaska and even the coldest areas in the lower 48 States. As noted by the commenters, turbine operators on the North Slope of Alaska have experienced problems with operation of the turbines in lean premix mode, and turbine manufacturers do not guarantee the performance of their turbines at the ambient temperatures typically found north of the Arctic Circle. Therefore, a subcategory for turbines operated north of the Arctic Circle has been established.

With regards to the rest of Alaska, EPA concluded that the final rule includes limits which will reduce or eliminate the need for add-on controls for the vast majority of turbines, and that these new emission limitations address the concerns of the commenters.

Modified and reconstructed offshore turbines have been given a subcategory due to the lack of space on platforms for additional controls.

The subcategories for these turbines are based on power output instead of heat input at peak load. Since the standards for these subcategories are similar to 40 CFR part 60, subpart GG, EPA used the same categories as subpart GG to avoid being less stringent than the existing emissions standards.

Comment: Several commenters had issues with periods of startup, shutdown and malfunction. Some commenters believed that the averaging times that are specified for continuous monitoring (using either a CEMS or parametric monitoring) were too short to accommodate such periods. The commenters believed that exceptions should be developed for periods of startup, shutdown and maintenance if 4-hour averages were maintained. One commenter suggested 30-day rolling averages, one commenter suggested 24-hour rolling averages, and one commenter suggested 12-month rolling averages.

One commenter wanted clarification of the applicability of the NO_X standards during periods of startup, shutdown and malfunction. Two commenters pointed out that while these periods of excess emissions were not considered violations, they might appear to be to State regulatory agencies or the public. Another commenter requested that EPA allow sources to permit emissions associated with startup and shutdown events where it is not feasible to have the same emission profile as normal operating conditions. This commenter requested that a clarification be made that deviating from a monitored parameter only results in excess emissions if emissions calculated from that parameter result in exceeding an emission limit for the averaging period used to demonstrate compliance.

One commenter was particularly concerned about combined cycle units with longer startup periods as part of a normal startup cycle. The commenter felt that this should not constitute a malfunction, and should not be reported in an excess emissions report. Another commenter asked that a reasonable startup period (up to 24 hours) be provided for units with SCR, since minimum temperatures must be met.

Response: The final rule states that excess emissions and deviations must be recorded during periods of startup, shutdown, and malfunction. We recognize that even for well-operated units with efficient NO_X emission controls, excess emission ''spikes'' during unit startup and shutdown are inevitable, and malfunctions of emission controls and process equipment occasionally occur. However, at all times, including periods of startup, shutdown, and malfunction, 40 CFR 60.11(d) requires affected units to be operated in a manner consistent with good air pollution control practice for minimizing emissions. Excess emissions data may be used to determine whether a facility's operation and maintenance procedures are consistent with 40 CFR 60.11(d). While continuous compliance is not required, excess emissions during startup, shutdown, and malfunction must be reported. Thus, we retained the 4-hour rolling average period in the final rule for simple cycle units. We realize that including units with heat recovery under the combustion turbine NSPS adds additional compliance issues for those units. Boiler NO_X emissions vary over short time periods and short averaging times make the output-based options unworkable due to the difficulty in continuously taking full advantage of the recovered thermal energy. For units with heat recovery and CEMS, the standard is therefore determined on a 30-day rolling average. Under the previous NSPS, heat recovery units are covered under either subpart Da, Db, or Dc, 40 CFR part 60. Those standards determine compliance based on a 30-day rolling average. In recognition of these factors, EPA concluded that a 30-day rolling average is the appropriate averaging time for units that are using recovered thermal energy. Since simple cycle turbines are used primarily for peaking applications, a 30-day average is not practical for these units. Initial compliance determinations could take several years, and once a unit is determined to be out of compliance it could take several years for the 30-day average to return below the standard.

In regards to parametric monitoring, a deviation from a monitored parameter only results in excess emissions if the calculations show an exceedence of the emission limit. This is clearly communicated in the final rule, in the section entitled ''How do I establish and document a proper parameter monitoring plan?'' Regarding the negative stigma, we cannot determine how other parties interpret the final rule. It is clear that continuous compliance is not a requirement of the final rule during periods of startup, shutdown, and malfunction.

B. NO_X Emission Standards

Comment: Numerous commenters recommended that there be some type of concentration-based standards for NO_X. One commenter said that while it applauds EPA's proposed shift to output-based standards, they might not be applicable in all situations. The commenter said that it is unclear how the calculation would work for a turbine with a bypass stack or another situation where heat is wasted. In addition, the commenter believed that an increased level of effort for monitoring parameters is required, which creates financial and technical burdens for compliance. The commenter recommended that EPA provide an optional concentration-based standard that can be used where data for calculating an output-based standard are unavailable or inappropriate.

One commenter recommended a ppmv standard consistent with current regulations, or a separate standard for simple cycle and combined cycle units. The commenter cited some of the following as rationale for its suggestion: Many State implementation plan regulations and best available control technology analyses are in ppmv, and 40 CFR part 60, subpart GG, is in ppmv; efficiency varies over load; carbon monoxide (CO) needs to be balanced; there are a limited number of units able to meet output-based limits without SCR; and output-based standards add complexity and computational and measurement uncertainty. Another commenter recommended that EPA allow optional concentration-based standards (i.e., ppmv corrected to 15 percent oxygen) so that if a source does not need energy efficiency adjustments to show compliance, it could choose to measure only emission concentrations at the stack.

Two commenters said that EPA should replace the output-based NO_X emission limit with a concentration-based standard for turbines less than 30 MW, which are primarily mechanical drive units. Similarly, several commenters said that EPA should provide optional concentration-based standards for all non-utility (mechanical drive) turbines; another solution would be to revise the monitoring approach to reduce cost and burden. The commenters' rationale was that mechanical drive units do not always include instruments that allow heat balance calculation of power output, and are frequently running at partial loads.

According to the commenters, a concentration-based limit would eliminate the need for variables that are difficult to accurately and readily obtain. Alternatively, these commenters felt that modifications should be made to include provisions in equation 4 of 40 CFR 60.4350(f)(3) for waste heat recovery when it is installed.

One commenter believed that limits should be specified on a concentration basis rather than on an output basis because some data show that lower concentrations can be attained at lower loads, yet, due to decreased efficiencies at lower loads, these emissions would exceed limitations on an output basis.

One commenter recommended a NO_X standard in ppm rather than an output-based standard for alternative fuels. The commenter said that in many cases, there is no demand for steam or thermal energy at or near landfills, so combined heat and power projects are unwarranted.

Response: We have considered the commenters' concerns, and have included an alternative concentration-based limit in the final rule for all turbines. Some units have difficulty with determining their power output, and adding a concentration-based emission limit significantly simplifies the regulation.

Comment: Several commenters said that turbines operating at partial load might not be able to meet the output-based limit. The commenters said that there are times when combustion turbines will run at partial load conditions, for example when a facility has not yet geared up to full production or when power is available from the grid at a lower cost than can be produced by the nonutility. According to the commenters, the turbine efficiency is lower at partial load operation, which leads to higher output-based emissions. Three commenters made the point that many combustion turbines shift out of lean premix mode into diffusion flame mode at lower loads, leading to increased NO_X emissions.

One commenter requested that the NO_X limits for partial loads be increased to account for lower thermal efficiencies at partial loads. One commenter suggested that part load operation for both gas and distillate oil revert to limits set on the basis of corrected NO_X concentrations (parts per million by volume dry (ppmvd) at 15 percent O_2). The commenter said that this coincides with operating schedules for existing General Electric dry low NO_X turbines, which are tuned to yield constant NO_X ppm throughout the operating load range. The commenter believed that this limit basis is also advantageous from the standpoint of compliance monitoring, since NO_X concentration can be measured directly on site when equipped with CEMS. Several commenters said that the NO_X emission standards should only apply at full load, and performance testing should be conducted at 90 to 100 percent of peak load or the highest load point achievable in practice. The commenters said that if EPA does not make this change, EPA should provide data and analysis supporting the applicability of the NO_X standard at partial load outside of the typical range for manufacturer guarantees.

One commenter said that the requirement in 40 CFR 60.4400(b) of the proposed rule to perform four tests between 70 and 100 percent load seems excessive. The commenter requested that this section also clarify that the four load points should be based upon the ambient conditions and fuel characteristics realized during the time of testing, since ambient temperature can affect the maximum or minimum operating load during a given test program. The commenter noted that operating at greater than 100 percent of peak load may also be possible, especially during cold (much less than 59 °F) ambient conditions.

Response: We indicated in the final rule that the NO_X performance testing should be conducted at full load operation, which is defined as plus or minus 25 percent of 100 percent of peak load, or the highest load physically achievable in practice. Only one load point is required for testing for the annual performance test. For continuous monitoring, an alternate limit has been established when the turbine is not operating at full load. Conducting the annual test at full load is consistent with the Stationary Combustion Turbines NESHAP, 40 CFR part 63, subpart YYYY.

Comment: Several commenters requested that EPA specify that the emission standards only apply for ambient temperatures ranging from 0 to 100 °F. Alternatively, the commenters asked EPA to provide data and analysis supporting the applicability of the NO_X standard at ambient temperatures outside of the typical range for manufacturer guarantees. Two commenters said that NO_X is higher at lower ambient temperatures, efficiencies are compromised at lower ambient temperatures, and cold intake air causes flame stability issues. The commenters also noted that EPA data in Alaska does not cover the winter operating season. The commenter provided some plots of emissions data for operations at low temperatures.

Response: EPA concluded that turbines do not operate optimally at ambient temperatures below 0 °F. Therefore, compliance demonstrations, such as annual testing, are required at ambient temperatures greater than 0 °F in the final rule. If you are using a CEMS for demonstrating compliance, alternate emissions standards apply when the ambient temperature is below 0 °F. We recognize that these temperatures may increase emissions from the turbine.

Comment: A number of commenters had concerns with the efficiencies that EPA used to determine the values for the output-based emission standards. One commenter stated that if EPA retained an output-based NO_X standard for units less than 30 MW, EPA should revise the efficiency basis for the standard, which is not supported by the docket material for industrial scale units. Three commenters said that the proposed NO_X emission standards needed to be revised to reflect the full range of turbine efficiencies that may be encountered during operation. Three commenters said that during the first 5 years of operation, the maximum load that can be achieved can decrease by as much as 5 percent while the thermal efficiency can decrease by as much as 2.5 percent.

One commenter said that 30 percent efficiency is not consistently achieved for small simple cycle turbines. The commenter recommended using 23 percent efficiency (LHV) at full load for turbines less than 3.5 MW, and 25 percent efficiency (LHV) at full load for the 3.5–30 MW turbines, to ensure that smaller turbines can achieve the NSPS at site conditions, which provide variability in efficiency.

Four commenters observed that the efficiencies on which the proposed output-based emissions were based only apply at full loads. One commenter said that the *Gas Turbine World* specifications show more than half of all models less than 30 MW have efficiencies lower than 30 percent. The commenter also said that lower loads have lower efficiencies, also many combined cycle units have efficiencies less than what EPA assumes. Another commenter asserted that EPA's standard is based on stack tests, conducted at steady state, so efficiency losses associated with changing load are not captured. In addition, the commenter believed that these efficiencies are only for ''out of the box'' turbines.

Two commenters said that EPA determined the 30 percent value based on turbine efficiency data in *Gas Turbine World*, which is based on LHV, but the commenters believed that EPA may have applied it inappropriately, as if it were HHV. If EPA had intended to base the efficiency assumption on HHV, it appears that the limit for turbines less than 30 MW was rounded down from 1.046 to 1.0 lb/MWh, according to the commenters. But if EPA intended to base the efficiency assumption on LHV, then the commenters determined that the limit should be 1.147 lb/MWh. The commenters said that even if EPA had intended the HHV efficiency, the rounding difference is almost 5 percent for the smaller turbine category, and this could be significant for turbines just meeting the 25 ppmv vendor guarantee.

Response: We developed alternative concentration-based standards, so that efficiency is no longer an issue if this alternative is chosen. In the final rule, we used a baseline efficiency of 23 percent for small turbines, 27 percent for medium turbines, and 44 percent for large turbines. The small turbine efficiency is based on the 40 CFR part 60, subpart GG, lowest efficiency, 25 percent based on LHV. The medium turbine efficiency is based on the top 90 percent of the medium turbine efficiencies listed in the 2005 Global Sourcing Guide for Gas Turbine Engines (*http://www.dieselpub.com/gsg*). The large turbine efficiency is based on the top 90 percent of the combined cycle efficiencies listed in the 2005 Global Sourcing Guide for Gas Turbine Engines. EPA concluded that these efficiencies are appropriate for turbines that elect to comply with the output-based standard.

Comment: Several commenters strongly opposed the NO_X emission limits established in the rule, as proposed. They contended that EPA's basis for establishing the limits was fundamentally flawed and not representative of current combustion turbines without the use of add-on controls. The commenters said that the proposed limits have no support in the docket's actual test data, and are the product of generalizations and faulty assumptions about the data, and must be withdrawn until they can be properly based on the data they cite.

According to the commenters, over 35 percent of the reported emission rates from natural gas-fired units and nearly all of those from fuel oil-fired units exceed the proposed output-based limits. Other concerns with the data expressed by the commenters included: Some power ranges are insufficiently represented because there are no data between 80 and 150 MW and there are few data over 160 MW; aeroderivative turbines are underrepresented; there were no useable emission rate data for several manufacturers; and EPA did not consider variability in load and may not have had adequate data for low temperatures. Another commenter believed that EPA did not heed the recommendations of the Gas Turbine

Association in their November 11, 2004, memorandum. In addition, this commenter believed that EPA did not match the population percentages to the data they reviewed. For example, the commenter said that almost 68 percent of the recent turbine orders are in the small category, yet only 21 percent of the data reviewed by EPA were in this subcategory. Additionally, the commenter said that for this subcategory, the maximum NO_X emission concentration listed is 27.8 ppm, which is above the level of 25 ppm used in proposing the standard for the small subcategory.

Many of the commenters provided suggested NO_X emission standards to EPA.

Response: While not all turbine models were represented in the data set, we concluded that it is representative of today's population of turbines. In addition, we obtained more data during the comment period, including emissions information for turbines less than 50 MMBtu/h. Also, our analysis included the addition of manufacturer guarantees and permit information, which, along with emissions data, gave us a clear picture of the achievability of the standards. The emission limits in the final rule have been revised, as appropriate, using these additional data and information. See table 1 of this preamble for the revised emission standards.

Comment: One commenter believed that there is a significant difference between aeroderivative turbines and frame type turbines in that aeroderivatives cannot employ low NO_X burners and must use water injection. While aeroderivatives may be guaranteed by the manufacturer to achieve 25 ppm at full load, the commenter believed that setting a standard at that level affords no cushion for operation below full load, especially in light of the short averaging times. Therefore, the commenter requested that EPA either raise the emission limit to allow for operational flexibility, or set different standards for different types of combustion turbines.

Response: We concluded that the majority of turbines are in some manner related to jet engine designs. The combustion turbine industry began in the aviation industry, and we concluded that it is not appropriate to subcategorize turbines based on design characteristics. The primary difference is the degree to which the turbines have been optimized for stationary applications. Furthermore, EPA concluded that there is no appropriate definition that separates aeroderivative and frame turbines.

In the final rule we increased the upper limit on the medium turbine category to 850 MMBtu/h. The medium turbine category covers the majority of turbines that the comments addressed. This category is based on the heat input to a 44 percent efficient 110 MW turbine. The standards in the final rule address the commenter's concerns.

Comment: Four commenters suggested emission limits for small turbines. One commenter recommended a fuel neutral standard of 150 ppmv for turbines less than 3 MW. Another commenter recommended a NO_X standard of 100 ppmv for natural gas-fired turbines less than 3 MW, and 150 ppmv for distillate oil-fired turbines less than 3 MW. One commenter said that if EPA retains turbines less than 3.5 MW in 40 CFR part 60, subpart KKKK, the NO_X emission limit for new construction should be 100 ppmv for natural gas and 175 ppmv for distillate oil; for modified or reconstructed turbines, the NO_X emission limit should be 150 ppmv for natural gas and 200 ppmv for distillate oil. The commenter recommended a concentration limit for mechanical drive turbines and an output-based limit based on an efficiency of 23 percent for power generators. Another commenter stated that if EPA retains turbines less than 3.5 MW in 40 CFR part 60, subpart KKKK, the NO_X emission limit for turbines between 1 and 3.5 MW should be no more stringent than 6 lb/MWh for natural gas, distillate oil and other fuels. The commenter's rationale was that this level is comparable to 40 CFR part 60, subpart GG, and significant improvements in control technologies have not been made since subpart GG was established.

Response: Based on the comments received, we revised the emission limitations in the final rule for small turbines, as shown in table 1 of this preamble. We received additional data from the turbine manufacturer for small turbines. Based on these data, we concluded that the majority of small turbines will be able to comply with the revised emission limitations given in the final rule. These numbers were based on data received from small turbine manufacturers during the public comment period.

Comment: Six commenters believed that the NO_X standards for turbines less than 30 MW were not consistently achievable in practice. Two of the commenters said that the standard for natural gas turbines 3 to 30 MW should be 42 ppmv. One commenter said that the standard for natural gas turbines 3.5 to 30 MW should be 42 ppmv for mechanical drive units, and based on 42 ppmv with an efficiency of 25 percent for power generation units. For distillate oil turbines 3.5 to 30 MW, the commenter said that the NO_X standard should be 96 ppmv for mechanical drive units, and based on 96 ppmv with an efficiency of 25 percent for power generation units. One commenter recommended a standard of 100 ppmv for oil-fired turbines. Three commenters suggested that EPA provide an option to pursue an alternative emission limit for retrofit applications that do not offer a 42 ppmv NO_X guarantee.

One commenter said that for turbines under 30 MW, a NO_X standard of 1.0 lb/MWh will be too stringent for some projects, particularly the smaller (less than 3.5 MW) facilities. The commenter believed that this will prevent the implementation of some projects that could provide lower emissions than the generation sources they are displacing. The commenter suggested that the limit should be no more stringent than 1.4 lb/MWh (25 ppm at 25 percent efficiency, LHV) for natural gas-fired turbines.

One commenter did not believe that any turbines less than 30 MW could meet the proposed emission limits. The commenter said that peaking turbines would not be able to meet the emission limits because they must operate at variable loads and also low temperatures increase NO_X emissions. The commenter believed that even at full load and 60 °F ambient temperature, a dry low NO_X turbine would just barely make the NO_X limit. Therefore, the commenter suggested that EPA increase the limit in combination with defining a limited range over which the limit is applicable. The commenter also noted that SCR has only been installed in a handful of simple cycle units and high temperature SCR is less reliable than standard SCR.

Response: We revised the emission limitations as well as the subcategory for medium turbines, as presented in table 1 of this preamble. The medium subcategory has been extended to cover additional turbines. The new subcategory on which these comments are based is from 50 MMBtu/h to 850 MMBtu/h. We concluded that, based on data submitted during the comment period, the new emission limitations in the final rule are achievable by most turbines in this subcategory without the use of add-on controls.

Comment: Several commenters said that the proposed NO_X limits for oil-fired units were too low. One commenter said that EPA's proposed output-based limits for oil-fired units cannot be achieved on simple cycle turbines with combustion controls. The commenter felt that the limit for oil-fired turbines, 1.2 lb/MWh, is de facto too stringent, and imposing an efficiency of 48 percent would be arbitrary and capricious. The commenter requested that EPA separate simple cycle from combined cycle, particularly for oil-fired units. One commenter requested that EPA either raise the emission limit for oil-fired combustion turbines, or at least allow large oil-fired peaking units to comply with the emission limit for small oil-fired units. Many of the commenters provided suggested emission levels for oil-fired units to EPA.

Response: EPA concluded that, based on data submitted during the comment period, the new emission limitations in the final rule for oil-fired turbines are achievable by most turbines without the use of add-on controls.

C. Definitions

Comment: Four commenters requested that EPA clarify the definition of efficiency. The commenters stated that the proposed definition is based on the LHV, but that EPA usually defines regulations based on HHV. The commenters believed that EPA may have intended to use HHV and requested clarification on whether efficiency should be based on the LHV or the HHV. One commenter stated that the LHV clause is unnecessary and should be removed because most air permits are written, modeled and reviewed upon the premise of the HHV of the fuel.

Response: In the proposed rule, we inadvertently defined efficiency in terms of LHV. Our intent was to use HHV. This change is reflected in the final rule.

V. Environmental and Economic Impacts

A. What are the air impacts?

We estimate that approximately 355 new stationary combustion turbines will be installed in the United States over the next 5 years and affected by the final rule. None of these units may need to install add-on controls to meet the NO_X limits required under the final rule. However, many new turbines will already be required to install add-on controls to meet NO_X reduction requirements under Prevention of Significant Deterioration (PSD) and New Source Review (NSR). Thus, we concluded that the NO_X reductions resulting from the final rule will essentially be zero. The expected SO2 reductions as a result of the final rule are approximately 830 tons per year (tpy) in the 5th year after promulgation of the standards.

Although we expect the final rule to result in a slight increase in electrical supply generated by unaffected sources (e.g., existing stationary combustion turbines), we concluded that this will not result in higher NO_X and SO_2 emissions from these sources. Other emission control programs such as the Acid Rain Program and PSD/NSR already promote or require emission controls that would effectively prevent emissions from increasing. All the emissions reductions estimates and assumptions have been documented in the docket to the final rule.

B. What are the energy impacts?

We do not expect any significant energy impacts resulting from the final rule. The only energy requirement is a potential small increase in fuel consumption, resulting from back pressure caused by operating an add-on emission control device, such as an SCR. However, most entities would be able to comply with the final rule without the use of any add-on control devices.

C. What are the economic impacts?

EPA prepared an economic impact analysis to evaluate the impacts the final rule would have on combustion turbines producers, consumers of goods and services produced by combustion turbines, and society. The analysis showed minimal changes in prices and output for products made by the industries affected by the final rule. The price increase for affected output is less than 0.003 percent, and the reduction in output is less than 0.003 percent for each affected industry. Estimates of impacts on fuel markets show price increases of less than 0.01 percent for petroleum products and natural gas, and price increases of 0.04 and 0.06 percent for base-load and peak-load electricity, respectively. The price of coal is expected to decline by about 0.002 percent, and that is due to a small reduction in demand for this fuel type. Reductions in output are expected to be less than 0.02 percent for each energy type, including base-load and peak-load electricity.

The social costs of the final rule are estimated at $0.4 million (2002 dollars). Social costs include the compliance costs, but also include those costs that reflect changes in the national economy due to changes in consumer and producer behavior in response to the compliance costs associated with a regulation. For the final rule, changes in energy use among both consumers and producers to reduce the impact of the regulatory requirements of the rule lead to the estimated social costs being less than the total annualized compliance cost estimate of $3.4 million (2002 dollars). The primary reason for the lower social cost estimate is the increase in electricity supply generated by unaffected sources (e.g., existing stationary combustion turbines), which offsets mostly the impact of increased electricity prices to consumers. The social cost estimates discussed above do not account for any benefits from emission reductions associated with the final rule.

For more information on these impacts, please refer to the economic impact analysis in the public docket.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), we must determine whether a regulatory action is ''significant'' and, therefore, subject to review by the Office of Management and Budget (OMB) and the requirements of the Executive Order. The Executive Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligation of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, OMB has notified EPA that it considers this a ''significant regulatory action'' within the meaning of the Executive Order. EPA submitted this action to OMB for review. Changes made in response to OMB suggestions or recommendations will be documented in the public record.

B. Paperwork Reduction Act

The information collection requirements in the final rule have been submitted for approval to OMB under the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by EPA has been assigned ICR No. 2177.01.

The final rule contains monitoring, reporting, and recordkeeping requirements. The information would be used by EPA to identify any new, modified, or reconstructed stationary combustion turbines subject to the NSPS and to ensure that any new stationary combustion turbines comply with the emission limits and other requirements. Records and reports would be necessary to enable EPA or States to identify new stationary combustion turbines that may not be in compliance with the requirements. Based on reported information, EPA would decide which units and what records or processes should be inspected.

The final rule does not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to EPA for which a claim of confidentiality is made will be safeguarded according to EPA policies in 40 CFR part 2, subpart B, Confidentiality of Business Information.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after July 6, 2006) is estimated to be 20,542 labor hours per year at an average total annual cost of $1,797,264. This estimate includes performance testing, continuous monitoring, semiannual excess emission reports, notifications, and recordkeeping. There are no capital/start-up costs or operation and maintenance costs associated with the monitoring requirements over the 3-year period of the ICR.

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. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9 and 48 CFR chapter 15.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedures Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's final rule on small entities, small entity is defined as: (1) A small business whose parent company has fewer than 100 or 1,000 employees, depending on size definition for the affected North American Industry Classification System (NAICS) code, or fewer than 4 billion kilowatt-hours (kW-hr) per year of electricity usage; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. It should be noted that small entities in one NAICS code would be affected by the final rule, and the small business definition applied to each industry by NAICS code is that listed in the Small Business Administration size standards (13 CFR part 121).

After considering the economic impacts of today's final rule on small entities, we conclude that today's action will not have a significant economic impact on a substantial number of small entities. We determined, based on the existing combustion turbines inventory and presuming the percentage of small entities in that inventory is representative of the percentage of small entities owning new turbines in the 5th year after promulgation, that one small entity out of 29 in the industries impacted by the final rule will incur compliance costs (in this case, only monitoring, recordkeeping, and reporting costs since control costs are zero) associated with the final rule. This small entity owns one affected turbine in the projected set of new combustion turbines. This affected small entity is estimated to have annual compliance costs of 0.3 percent of its revenues. The final rule is likely to also increase profits for the small firms and increase revenues for the many small communities (in total, 28 small entities) using combustion turbines that are not affected by the final rule as a result of the very slight increase in market prices. For more information on the results of the analysis of small entity impacts, please refer to the economic impact analysis in the docket.

Although the final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of the final rule on small entities. In the final rule, the Agency is applying the minimum level of control and the minimum level of monitoring, recordkeeping, and reporting to affected sources allowed by the CAA. In addition, as mentioned earlier in this preamble, new turbines with heat inputs less than 10.7 GJ (10 MMBtu) per hour are not subject to the final rule. This provision should reduce the size of small entity impacts. We continue to be interested in the potential impacts of the final rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost effective, or least burdensome alternative that achieves the objective of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that the final rule contains no Federal mandates that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Thus, the final rule is not subject to the requirements of sections 202 and 205 of the UMRA. In addition, EPA has determined that the final rule contains no regulatory requirements that might significantly or uniquely affect small governments because they contain no requirements that apply to such governments or impose obligations upon them. Therefore, the final rule is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

Executive Order 13132 (64 FR 43255, August 10, 1999) requires us to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' are defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

The final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to the final rule.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175 (65 FR 67249, November 6, 2000) requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' ''Policies that have tribal implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on one or more Indian tribes, on the relationship between the Federal government and the Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes.''

The final rule does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. We do not know of any stationary combustion turbines owned or operated by Indian tribal governments. However, if there are any, the effect of the final rule on communities of tribal governments would not be unique or disproportionate to the effect on other communities. Thus, Executive Order 13175 does not apply to the final rule.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, we must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives.

The final rule is not subject to Executive Order 13045 because it is not an economically significant action as defined under Executive Order 12866.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

Today's action is not a ''significant energy action'' as defined in Executive Order 13211 because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

An increase in petroleum product output, which includes increases in fuel production, is estimated at less than 0.01 percent, or about 600 barrels per day based on 2004 U.S. fuel production nationwide. A reduction in coal production is estimated at 0.00003 percent, or about 3,000 short tpy based on 2004 U.S. coal production nationwide. The reduction in electricity output is estimated at 0.02 percent, or about 5 billion kW-hr per year based on 2000 U.S. electricity production nationwide.

Production of natural gas is expected to increase by 4 million cubic feet per day. The maximum of all energy price increases, which include increases in natural gas prices as well as those for petroleum products, coal, and electricity, is estimated to be a 0.04 percent increase in peak-load electricity rates nationwide. Energy distribution costs may increase by no more than the same amount as electricity rates. We expect that there will be no discernable impact on the import of foreign energy supplies, and no other adverse outcomes are expected to occur with regards to energy supplies.

Also, the increase in the cost of energy production should be minimal given the very small increase in fuel consumption resulting from back pressure related to operation of add-on emission control devices, such as SCR. All of the estimates presented above account for some passthrough of costs to consumers as well as the direct cost impact to producers.

For more information on these estimated energy effects, please refer to the economic impact analysis for the final rule. This analysis is available in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113; 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

The final rule involves technical standards. EPA cites the following methods in the final rule: EPA Methods 1, 2, 3A, 6, 6C, 7E, 8, 19, and 20 of 40 CFR part 60, appendix A; and Performance Specifications (PS) 2 of 40 CFR part 60, appendix B.

In addition, the final rule cites the following standards that are also incorporated by reference in 40 CFR part 60, section 17: ASTM D129–00

(Reapproved 2005), ASTM D1072–90 (Reapproved 1999), ASTM D1266 98 (Reapproved 2003), ASTM D1552–03, ASTM D2622–05, ASTM D3246–05, ASTM D4057–95 (Reapproved 2000), ASTM D4084–05, ASTM D4177–95 (Reapproved 2000), ASTM D4294–03, ASTM D4468–85 (Reapproved 2000), ASTM D4810–88 (Reapproved 1999), ASTM D5287–97 (Reapproved 2002), ASTM D5453–05, ASTM D5504–01, ASTM D6228–98 (Reapproved 2003), ASTM D6667–04, and Gas Processors Association Standard 2377–86.

Consistent with the NTTAA, EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods/ performance specifications. No applicable voluntary consensus standards were identified for EPA Methods 8 and 19. The search and review results have been documented and are placed in the docket for the final rule.

One voluntary consensus standard was identified as an acceptable alternative for the EPA methods cited in this rule. The voluntary consensus standard ASME PTC 19–10–1981—Part 10, ''Flue and Exhaust Gas Analyses,'' is cited in this rule for its manual method for measuring the sulfur dioxide content of exhaust gas. This part of ASME PTC 19–10–1981—Part 10 is an acceptable alternative to EPA Methods 6 and 20 (sulfur dioxide only).

In addition to the voluntary consensus standards EPA uses in the final rule, the search for emissions measurement procedures identified 11 other voluntary consensus standards. EPA determined that nine of these 11 standards identified for measuring air emissions or surrogates subject to emission standards in the final rule were impractical alternatives to EPA test methods/performance specifications for the purposes of the final rule. Therefore, EPA does not intend to adopt these standards. See the docket for the reasons for the determinations of these methods.

Two of the 11 voluntary consensus standards identified in this search were not available at the time the review was conducted for the purposes of the final rule because they are under development by a voluntary consensus body. See the docket for the list of these methods.

Sections 60.4345, 60.4360, 60.4400 and 60.4415 of the final rule discuss EPA testing methods, performance specifications, and procedures required. Under 40 CFR 63.7(f) and 40 CFR 63.8(f) of subpart A of the General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of EPA testing methods, performance specifications, or procedures.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. section 801 *et. seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing today's final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). The final rule will be effective on July 6, 2006.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: February 9, 2006.

Stephen L. Johnson,

Administrator.

Editorial Note: This document was received by the Office of the Federal Register on June 28, 2006.

■ For the reasons stated in the preamble, title 40, chapter I, part 60, of the Code of Federal Regulations is amended as follows:

PART 60—[AMENDED]

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A—[Amended]

■ 2. Section 60.17 is amended by revising paragraphs (a), (h)(4), and (m)(1), and reserving paragraph (m)(2) to read as follows:

§ 60.17 Incorporation by reference.

* * * * *

(a) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959; or ProQuest, 300 North Zeeb Road, Ann Arbor, MI 48106.

(1) ASTM A99–76, 82 (Reapproved 1987), Standard Specification for Ferromanganese, incorporation by reference (IBR) approved for § 60.261.

(2) ASTM A100–69, 74, 93, Standard Specification for Ferrosilicon, IBR approved for § 60.261.

(3) ASTM A101–73, 93, Standard Specification for Ferrochromium, IBR approved for § 60.261.

(4) ASTM A482–76, 93, Standard Specification for Ferrochromesilicon, IBR approved for § 60.261.

(5) ASTM A483–64, 74 (Reapproved 1988), Standard Specification for Silicomanganese, IBR approved for § 60.261.

(6) ASTM A495–76, 94, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for § 60.261.

(7) ASTM D86–78, 82, 90, 93, 95, 96, Distillation of Petroleum Products, IBR approved for §§ 60.562–2(d), 60.593(d), and 60.633(h).

(8) ASTM D129–64, 78, 95, 00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§ 60.106(j)(2), 60.335(b)(10)(i), and Appendix A: Method 19, 12.5.2.2.3.

(9) ASTM D129–00 (Reapproved 2005), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for § 60.4415(a)(1)(i).

(10) ASTM D240–76, 92, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§ 60.46(c), 60.296(b), and Appendix A: Method 19, Section 12.5.2.2.3.

(11) ASTM D270–65, 75, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.1.

(12) ASTM D323–82, 94, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§ 60.111(l), 60.111a(g), 60.111b(g), and 60.116b(f)(2)(ii).

(13) ASTM D388–77, 90, 91, 95, 98a, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41(f) of subpart D of this part, 60.45(f)(4)(i), 60.45(f)(4)(ii), 60.45(f)(4)(vi), 60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, and 60.251(b) and (c) of subpart Y of this part.

(14) ASTM D388–77, 90, 91, 95, 98a, 99 (Reapproved 2004) $^{\varepsilon 1}$, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.24(h)(8), 60.41Da of subpart Da of this part, and 60.4102.

(15) ASTM D396–78, 89, 90, 92, 96, 98, Standard Specification for Fuel Oils,

IBR approved for §§ 60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, 60.111(b) of subpart K of this part, and 60.111a(b) of subpart Ka of this part.

(16) ASTM D975–78, 96, 98a, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.111(b) of subpart K of this part and 60.111a(b) of subpart Ka of this part.

(17) ASTM D1072–80, 90 (Reapproved 1994), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.335(b)(10)(ii).

(18) ASTM D1072–90 (Reapproved 1999), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.4415(a)(1)(ii).

(19) ASTM D1137–53, 75, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for § 60.45(f)(5)(i).

(20) ASTM D1193–77, 91, Standard Specification for Reagent Water, IBR approved for Appendix A: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.

(21) ASTM D1266–87, 91, 98, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j)(2) and 60.335(b)(10)(i).

(22) ASTM D1266–98 (Reapproved 2003) ε^1, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for § 60.4415(a)(1)(i).

(23) ASTM D1475–60 (Reapproved 1980), 90, Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for § 60.435(d)(1), Appendix A: Method 24, Section 6.1; and Method 24A, Sections 6.5 and 7.1.

(24) ASTM D1552–83, 95, 01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§ 60.106(j)(2), 60.335(b)(10)(i), and Appendix A: Method 19, Section 12.5.2.2.3.

(25) ASTM D1552–03, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for § 60.4415(a)(1)(i).

(26) ASTM D1826–77, 94, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§ 60.45(f)(5)(ii), 60.46(c)(2), 60.296(b)(3), and Appendix A: Method 19, Section 12.3.2.4.

(27) ASTM D1835–87, 91, 97, 03a, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for § 60.41Da of subpart Da of this part.

(28) ASTM D1835–82, 86, 87, 91, 97, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for § 60.41b of subpart Db of this part.

(29) ASTM D1835–86, 87, 91, 97, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for § 60.41c of subpart Dc of this part.

(30) ASTM D1945–64, 76, 91, 96, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f)(5)(i).

(31) ASTM D1946–77, 90 (Reapproved 1994), Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§ 60.18(f)(3), 60.45(f)(5)(i), 60.564(f)(1), 60.614(e)(2)(ii), 60.614(e)(4), 60.664(e)(2)(ii), 60.664(e)(4), 60.704(d)(2)(ii), and 60.704(d)(4).

(32) ASTM D2013–72, 86, Standard Method of Preparing Coal Samples for Analysis, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(33) ASTM D2015–77 (Reapproved 1978), 96, Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for § 60.45(f)(5)(ii), 60.46(c)(2), and Appendix A: Method 19, Section 12.5.2.1.3.

(34) ASTM D2016–74, 83, Standard Test Methods for Moisture Content of Wood, IBR approved for Appendix A: Method 28, Section 16.1.1.

(35) ASTM D2234–76, 96, 97b, 98, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for Appendix A: Method 19, Section 12.5.2.1.1.

(36) ASTM D2369–81, 87, 90, 92, 93, 95, Standard Test Method for Volatile Content of Coatings, IBR approved for Appendix A: Method 24, Section 6.2.

(37) ASTM D2382–76, 88, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§ 60.18(f)(3), 60.485(g)(6), 60.564(f)(3), 60.614(e)(4), 60.664(e)(4), and 60.704(d)(4).

(38) ASTM D2504–67, 77, 88 (Reapproved 1993), Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for § 60.485(g)(5).

(39) ASTM D2584–68 (Reapproved 1985), 94, Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for § 60.685(c)(3)(i).

(40) ASTM D2597–94 (Reapproved 1999), Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, IBR approved for § 60.335(b)(9)(i).

(41) ASTM D2622–87, 94, 98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry,'' IBR approved for §§ 60.106(j)(2) and 60.335(b)(10)(i).

(42) ASTM D2622–05, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry,'' IBR approved for § 60.4415(a)(1)(i).

(43) ASTM D2879–83, 96, 97, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§ 60.111b(f)(3), 60.116b(e)(3)(ii), 60.116b(f)(2)(i), and 60.485(e)(1).

(44) ASTM D2880–78, 96, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§ 60.111(b), 60.111a(b), and 60.335(d).

(45) ASTM D2908–74, 91, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for § 60.564(j).

(46) ASTM D2986–71, 78, 95a, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved for Appendix A: Method 5, Section 7.1.1; Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(47) ASTM D3173–73, 87, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(48) ASTM D3176–74, 89, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for § 60.45(f)(5)(i) and Appendix A: Method 19, Section 12.3.2.3.

(49) ASTM D3177–75, 89, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(50) ASTM D3178–73 (Reapproved 1979), 89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for § 60.45(f)(5)(i).

(51) ASTM D3246–81, 92, 96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b)(10)(ii).

(52) ASTM D3246–05, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.4415(a)(1)(ii).

(53) ASTM D3270–73T, 80, 91, 95, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for Appendix A: Method 13A, Section 16.1.

(54) ASTM D3286–85, 96, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(55) ASTM D3370–76, 95a, Standard Practices for Sampling Water, IBR approved for § 60.564(j).

(56) ASTM D3792–79, 91, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for Appendix A: Method 24, Section 6.3.

(57) ASTM D4017–81, 90, 96a, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for Appendix A: Method 24, Section 6.4.

(58) ASTM D4057–81, 95, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.3.

(59) ASTM D4057–95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4415(a)(1).

(60) ASTM D4084–82, 94, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for § 60.334(h)(1).

(61) ASTM D4084–05, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §§ 60.4360 and 60.4415(a)(1)(ii).

(62) ASTM D4177–95, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.1.

(63) ASTM D4177–95 (Reapproved 2000), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4415(a)(1).

(64) ASTM D4239–85, 94, 97, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(65) ASTM D4294–02, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.335(b)(10)(i).

(66) ASTM D4294–03, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.4415(a)(1)(i).

(67) ASTM D4442–84, 92, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for Appendix A: Method 28, Section 16.1.1.

(68) ASTM D4444–92, Standard Test Methods for Use and Calibration of Hand-Held Moisture Meters, IBR approved for Appendix A: Method 28, Section 16.1.1.

(69) ASTM D4457–85 (Reapproved 1991), Test Method for Determination of Dichloromethane and 1, 1, 1-Trichloroethane in Paints and Coatings by Direct Injection into a Gas Chromatograph, IBR approved for Appendix A: Method 24, Section 6.5.

(70) ASTM D4468–85 (Reapproved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, IBR approved for §§ 60.335(b)(10)(ii) and 60.4415(a)(1)(ii).

(71) ASTM D4629–02, Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection, IBR approved for § 60.335(b)(9)(i).

(72) ASTM D4809–95, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for §§ 60.18(f)(3), 60.485(g)(6), 60.564(f)(3), 60.614(d)(4), 60.664(e)(4), and 60.704(d)(4).

(73) ASTM D4810–88 (Reapproved 1999), Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length of Stain Detector Tubes, IBR approved for §§ 60.4360 and 60.4415(a)(1)(ii).

(74) ASTM D5287–97 (Reapproved 2002), Standard Practice for Automatic Sampling of Gaseous Fuels, IBR approved for § 60.4415(a)(1).

(75) ASTM D5403–93, Standard Test Methods for Volatile Content of Radiation Curable Materials, IBR approved for Appendix A: Method 24, Section 6.6.

(76) ASTM D5453–00, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for § 60.335(b)(10)(i).

(77) ASTM D5453–05, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for § 60.4415(a)(1)(i).

(78) ASTM D5504–01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for §§ 60.334(h)(1) and 60.4360.

(79) ASTM D5762–02, Standard Test Method for Nitrogen in Petroleum and Petroleum Products by Boat-Inlet Chemiluminescence, IBR approved for § 60.335(b)(9)(i).

(80) ASTM D5865–98, Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for § 60.45(f)(5)(ii), 60.46(c)(2), and Appendix A: Method 19, Section 12.5.2.1.3.

(81) ASTM D6216–98, Standard Practice for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications, IBR approved for Appendix B, Performance Specification 1.

(82) ASTM D6228–98, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for § 60.334(h)(1).

(83) ASTM D6228–98 (Reapproved 2003), Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §§ 60.4360 and 60.4415.

(84) ASTM D6366–99, Standard Test Method for Total Trace Nitrogen and Its Derivatives in Liquid Aromatic Hydrocarbons by Oxidative Combustion and Electrochemical Detection, IBR approved for § 60.335(b)(9)(i).

(85) ASTM D6522–00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for § 60.335(a).

(86) ASTM D6667–01, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for § 60.335(b)(10)(ii).

(87) ASTM D6667–04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for § 60.4415(a)(1)(ii).

(88) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), IBR approved for Appendix B

to part 60, Performance Specification 12A, Section 8.6.2.

(89) ASTM E168–67, 77, 92, General Techniques of Infrared Quantitative Analysis, IBR approved for §§ 60.593(b)(2) and 60.632(f).

(90) ASTM E169–63, 77, 93, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§ 60.593(b)(2) and 60.632(f).

(91) ASTM E260–73, 91, 96, General Gas Chromatography Procedures, IBR approved for §§ 60.593(b)(2) and 60.632(f).

* * * * *

(h) * * *

(4) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], IBR approved for Tables 1 and 3 of subpart EEEE, Tables 2 and 4 of subpart FFFF, and §§ 60.4415(a)(2) and 60.4415(a)(3) of subpart KKKK of this part.

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(m) * * *

(1) Gas Processors Association Method 2377–86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, IBR approved for §§ 60.334(h)(1), 60.4360, and 60.4415(a)(1)(ii).

(2) [Reserved]

■ 3. Part 60 is amended by reserving subpart IIII and subpart JJJJ and by adding subpart KKKK to read as follows:

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

Introduction

§ 60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Applicability

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

§ 60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in § 60.4420(i), are exempt from the nitrogen oxides (NO_X) emission limits in § 60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO_X emission limits in § 60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_X) and sulfur dioxide (SO_2).

§ 60.4320 What emission limits must I meet for nitrogen oxides (NO_X)?

(a) You must meet the emission limits for NO_X specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X.

§ 60.4325 What emission limits must I meet for NO_X if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

§ 60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1) or (a)(2) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

General Compliance Requirements

§ 60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

Monitoring

§ 60.4335 How do I demonstrate compliance for NO_X if I use water or steam injection?

(a) If you are using water or steam injection to control NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

§ 60.4340 How do I demonstrate continuous compliance for NO_X if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with § 60.4400 to demonstrate continuous compliance. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§ 60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.

(iii) For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in § 75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in § 75.19(c)(1)(iv)(H).

§ 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NO_X CEMS is chosen:

(a) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in § 60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

§ 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in § 60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in § 60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under § 60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under § 60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_X)_h \,*\, (HI)_h}{P} \qquad (\text{Eq. } 1)$$

Where:

E = hourly NO_X emission rate, in lb/MWh,

$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D–15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad (\text{Eq. } 2)$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

$(Pe)_t$ = electrical or mechanical energy output of the combustion turbine in MW,

$(Pe)_c$ = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \qquad (\text{Eq. } 3)$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and $3.413 \times 10_6$ = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_X)_m}{BL \,*\, AL} \qquad (\text{Eq. } 4)$$

Where:

E = NO_X emission rate in lb/MWh,

$(NO_X)_m$ = NO_X emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in § 60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in § 60.4380(b)(1).

§ 60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§ 60.4335 and 60.4340 must be monitored during the performance test required under § 60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO_X emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in § 75.19 or the NO_X emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in § 75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

§ 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in § 60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in § 60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see § 60.17), which measure the major sulfur compounds, may be used.

§ 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§ 60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in § 60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in § 60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

Reporting

§ 60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with § 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with § 60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

§ 60.4380 How are excess emissions and monitor downtime defined for NO_X?

For the purpose of reports required under § 60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with § 60.4320, as established during the performance test required in § 60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO_X control will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§ 60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in § 60.4320. For the purposes of this subpart, a ''4-hour rolling average NO_X emission rate'' is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a ''30-day rolling average NO_X emission rate'' is the arithmetic average of all hourly NO_X emission data in ppm or

ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

§ 60.4385 How are excess emissions and monitoring downtime defined for SO_2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

§ 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NO_X limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO_X limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§ 60.4395 When must I submit my reports?

All reports required under § 60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Performance Tests

§ 60.4400 How do I conduct the initial and subsequent performance tests, regarding NO_X?

(a) You must conduct an initial performance test, as required in § 60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \qquad \text{(Eq. 5)}$$

Where:

E = NO_X emission rate, in lb/MWh

1.194×10^{-7} = conversion constant, in lb/dscf-ppm

$(NO_X)_c$ = average NO_X concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to § 60.4350(f)(2); or

(ii) Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the NO_X emission rate in lb/MWh.

(2) Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

(B) For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or

(C) For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with § 60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable § 60.4320 NO_X emission limit.

(4) Compliance with the applicable emission limit in § 60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in § 60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in § 60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

§ 60.4405 How do I perform the initial performance test if I have chosen to install a NO_X-diluent CEMS?

If you elect to install and certify a NO_X-diluent CEMS under § 60.4345, then the initial performance test required under § 60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under § 60.4320 and to provide the required reference method data for the RATA of the CEMS described under § 60.4335.

(d) Compliance with the applicable emission limit in § 60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls in accordance with § 60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in § 60.4355.

§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in § 60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see § 60.17) for natural gas or ASTM D4177 (incorporated by reference, see § 60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see § 60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see § 60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see § 60.17).

(2) Measure the SO_2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, ''Flue and Exhaust Gas Analyses,'' manual methods for sulfur dioxide (incorporated by reference, see § 60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2 emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \qquad (Eq.\ 6)$$

Where:

E = SO_2 emission rate, in lb/MWh

1.664×10^{-7} = conversion constant, in lb/dscf-ppm

$(SO_2)_c$ = average SO_2 concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to § 60.4350(f)(2); or

(3) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see § 60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the SO_2 emission rate in lb/MWh.

(b) [Reserved]

Definitions

§ 60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NO_X emissions are higher than the applicable emission limit in § 60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in § 60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

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. 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 British thermal units (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.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore platforms.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

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), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit 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 unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

TABLE 1.—TO SUBPART KKKK OF PART 60.—NITROGEN OXIDE EMISSION LIMITS FOR NEW STATIONARY COMBUSTION TURBINES

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing natural gas, electric generating.	≤ 50 MMBtu/h	42 ppm at 15 percent O_2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas.	> 850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating.	≤ 50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive.	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas.	> 850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas.	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas.	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).

TABLE 1.—TO SUBPART KKKK OF PART 60.—NITROGEN OXIDE EMISSION LIMITS FOR NEW STATIONARY COMBUSTION TURBINES—Continued

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0°F.	≤ 30 MW output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0°F.	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine.	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

[FR Doc. 06–5945 Filed 7–5–06; 8:45 am]

BILLING CODE 6560–50–P