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Part III

Environmental Protection Agency

40 CFR Part 60
Standards of Performance for Stationary Gas Turbines; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[OAR–2002–0053, FRL–7780–6]

RIN 2060–AK35

Standards of Performance for Stationary Gas Turbines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; amendments.

SUMMARY: This action promulgates amendments to several sections of the standards of performance for stationary gas turbines in 40 CFR part 60, subpart GG. The amendments will codify several alternative testing and monitoring procedures that have routinely been approved by EPA. The amendments will also reflect changes in nitrogen oxides (NO_X) emission control technologies and turbine design since the standards were promulgated.

DATES: The final rule is effective July 8, 2004. 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 8, 2004.

ADDRESSES: *Docket.* The EPA has established a docket for this action under Docket ID No. OAR–2002–0053. All documents in the docket are listed in EDOCKET index at *http://www.epa.gov/edocket.* Although listed in the index, some information is not publicly available, *i.e.*, 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 in EDOCKET or in hard copy at the Air Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Avenue, NW, Washington, DC 20460. 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 Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Jaime Pagan, Combustion Group, Emission Standards Division (C439–01), U.S. EPA, Research Triangle Park, North Carolina 27711; telephone number (919) 541–5340; facsimile number (919) 541–5450; electronic mail address *pagan.jaime@epa.gov.*

SUPPLEMENTARY INFORMATION: *Regulated Entities.* Entities potentially regulated by this action are those that own and operate stationary gas turbines, and are the same as the existing rule in 40 CFR part 60, subpart GG. Regulated categories and entities include:

Category	NAICS	SIC	Examples of regulated entities
Any industry using a 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.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. To determine whether your facility is regulated by this action, you should examine the applicability criteria in § 60.330 of the final rule. If you have questions regarding the applicability of this action to a particular entity, consult the contact person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Docket. The EPA has established an official public docket for this action under Docket ID No. OAR–2002–0053. The official public docket consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. Although a part of the official docket, the public docket does not include Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. The official public docket is the collection of materials that is available for public viewing at the Air Docket in the EPA Docket Center, Room B108, 1301 Constitution Ave., NW., Washington, DC 20460. The EPA Docket Center 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. The telephone number for the Air Docket is (202) 566–1742. A reasonable fee may be charged for copying docket materials.

Electronic Access. You may access this **Federal Register** document electronically through the EPA Internet under the **Federal Register** listings at *http://www.epa.gov/fedrgstr/.*

An electronic version of the public docket is available through EPA's electronic public docket and comment system, EPA Dockets. You may use EPA Dockets at *http://www.epa.gov/edocket/* to view public comments, access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically. Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the docket facility located above. Once in the system, select ''search,'' then key in the appropriate docket identification number.

World Wide Web (WWW). In addition to being available in the docket, an electronic copy of the final rule is also available on the WWW through the Technology Transfer Network (TTN). Following signature, a copy of the promulgated final rule will be posted 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. If more information regarding the TTN is needed, call the TTN HELP line at (919) 541–5384.

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 Circuit by September 7, 2004. Under section 307(d)(7)(B) of the CAA, only an objection to a rule or procedure 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 the final rule may not be challenged separately in any civil or criminal proceeding brought to enforce these requirements.

Background Information Document. During the comment period, EPA received 23 comment letters on the proposal and direct final rule. A background information document (BID) (''Response to Public Comments on Proposed Standards of Performance for Stationary Gas Turbines,'') containing

EPA's responses to each public comment is available in Docket ID No. OAR–2002–0053.

Outline. The information presented in this preamble is organized as follows:

I. Background

Under section 111 of the CAA, 42 U.S.C. 7411, the EPA promulgated standards of performance for stationary gas turbines (40 CFR part 60, subpart GG). The standards were promulgated on September 10, 1979 (44 FR 52798). Since that time, many advances in the design of the NO_X emission controls used in gas turbines have occurred. Additional test methods have also been developed to measure emissions from gas turbines and the sulfur content of gaseous fuels. As a result of these advances, we have had many requests for case-by-case approvals of alternative testing and monitoring procedures for subpart GG. We are promulgating the amendments to subpart GG to codify the alternatives that have been routinely approved. Additionally, we are attempting to harmonize, where appropriate, the provisions of subpart GG with the monitoring provisions of 40 CFR part 75, the continuous emission monitoring requirements of the acid rain program under title IV of the CAA, since many existing and new gas turbines are subject to both regulations.

On April 14, 2003, we published a direct final rule (68 FR 17990) and a parallel proposal (68 FR 18003) amending the standards of performance for stationary gas turbines (40 CFR part 60, subpart GG). We stated in the preambles to the direct final rule and parallel proposal that if we received adverse comments on one or more distinct provisions of the direct final rule, we would publish a timely withdrawal of those distinct provisions in the **Federal Register**. The preamble to the direct final rule stated that the deadline for submitting public comments was May 14, 2003, and the effective date of the provisions would be May 29, 2003. The preamble to the proposal also stated that if a public hearing was requested by April 24, 2003, the hearing would be held on May 14, 2003, and the comment period would be extended until 30 days after the date of the public hearing. Since a public hearing was requested, the comment period was extended until June 13, 2003. The entire direct final rule was withdrawn in order to avoid the direct final rule becoming effective before all public comments were received.

II. Discussion of Revisions

A. Continuous Monitoring Options

Under the original provisions of subpart GG, 40 CFR part 60, any affected unit with a water injection system was required to install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. These operating parameters demonstrate that a turbine continues to operate under the same performance conditions as those documented during the initial and any subsequent compliance tests, thus providing reasonable assurance of compliance with the NO_X standard. We are amending the regulation to allow the use of NO_X continuous emission monitoring systems (CEMS) to demonstrate compliance, as detailed in the following paragraphs.

Owners or operators of turbines that commenced construction, reconstruction, or modification after October 3, 1977, but before July 8, 2004, and that use water or steam injection to control NO_X emissions can continue to use the NO_X monitoring system which is currently being used, or may elect to use a NO_X CEMS. The CEMS must be installed, operated, and maintained according to the appropriate performance specification requirements in 40 CFR part 60, appendix B. Alternatively, sources may choose to use data from a NO_X CEMS that is certified according to the requirements of 40 CFR part 75. Any owners or operators of turbines constructed, reconstructed, or modified in this time period that do not use water or steam injection and that have received EPA or local permitting authority approval of an alternative monitoring strategy can continue to follow the conditions of the petition approval.

For new turbines constructed after July 8, 2004, and using water or steam injection for NO_X control, owners/operators can elect to use either the existing requirements for continuous water or steam to fuel ratio monitoring or may elect to use a CEMS to monitor NO_X. The CEMS must be installed and certified according to Performance Specifications (PS) 2 and 3 of 40 CFR part 60, appendix B. Alternatively, sources may choose to use data from a NO_X CEMS that is certified according to the requirements of 40 CFR part 75, appendix A.

Owners or operators of new turbines that commence construction after July 8, 2004, and do not use water or steam injection to control NO_X emissions can use a NO_X CEMS as an alternative to continuously monitoring fuel consumption and water or steam to fuel ratio, provided the CEMS is installed and certified according to PS 2 and 3 of 40 CFR part 60, appendix B and 40 CFR 60.13 or the requirements of 40 CFR part 75, appendix A. An acceptable alternative to installation of a NO_X CEMS is continuous parameter monitoring. If this option is chosen, owners or operators of uncontrolled diffusion flame turbines must continuously monitor at least four parameters indicative of the unit's NO_X formation characteristics. For lean premix turbines, continuous monitoring of parameters that indicate whether the turbine is operating in the lean premixed combustion mode is required. Examples of these parameters may include percentage of full load, turbine exhaust temperature, combustion reference temperature, compressor discharge pressure, fuel and air valve positions, dynamic pressure pulsations, internal guide vane position, and flame detection or flame scanner conditions. Definitions for diffusion flame turbine and lean premix turbine consistent with those in the combustion turbine final rule have been added to the definitions section of the final rule. Parameters that indicate proper operation of the emission control device must be monitored for turbines that use selective catalytic reduction. In all cases, the acceptable values and ranges for the parameters must be established during the initial performance test for the turbine and recorded in a parameter monitoring plan, to be kept on-site.

If the option to use a NO_X CEMS is chosen, we have specified the minimum data requirements. For full operating hours, each monitor must complete at least one cycle of operation (including sampling, analyzing, and data recording) for each 15-minute quadrant of the hour. For partial unit operating hours, one valid data point must be obtained for each quadrant of the hour for which the unit is operating. A minimum of two valid data points in two different 15-minute quadrants are required for hours in which required quality assurance and maintenance activities are performed on the CEMS. This data must be reduced to hourly averages for purposes of identifying excess emissions. The data acquisition and handling system must record the hourly NO_X emissions as well as the International Organization for Standardization (ISO) standard conditions (if applicable).

In lieu of recording the ISO standard conditions, a worst case ISO correction factor can be calculated using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (H_o), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation. By using worst case parameters in this equation, the owner/operator can ensure compliance in all situations without having to continuously monitor temperature, humidity and pressure. Several case-by-case determinations performed by EPA have accepted this methodology as an alternative to continuous monitoring of atmospheric conditions.

No NO_X or oxygen (O_2) CEMS data generated using the missing data substitution procedures in 40 CFR part 75 may be used to demonstrate compliance with the subpart GG, 40 CFR part 60, emission limits. Instead, these periods of missing data are counted as monitor downtime in the excess emissions and monitoring report required under 40 CFR 60.7(c). For turbines using NO_X CEMS, we have defined excess emissions as any unit operating hour during which the 4-hour rolling average NO_X concentration exceeds the applicable emission limit.

The 4-hour averaging period for defining excess emissions approximates the amount of time typically required to conduct a performance test of a combustion turbine using EPA Method 20. The 4-hour averaging period is relatively short compared to 24-hour and 30-day averaging times used for other types of combustion devices (*e.g.,* boilers). However, for these other combustion units, a longer averaging period is generally needed to account for variability in the NO_X emissions, particularly when solid fuels are fired. Combustion turbines typically use natural gas or diesel, which both have relatively uniform predictable NO_X emissions. Therefore, a shorter averaging time such as 4 hours is considered adequate to assess compliance. An averaging time of 1 hour was also considered, but was rejected since 4 hours more closely represents the typical duration of a combustion turbine stack test and will account for any minor temporal variation in the NO_X emissions.

To determine the 4-hour rolling averages, each period of 4 consecutive unit operating hours is assessed (*i.e.*, the current unit operating hour and the 3 unit operating hours immediately preceding it).

We are allowing the use of NO_X CEMS as an alternative to continuously monitoring fuel consumption and water or steam to fuel ratio because the majority of new turbines do not rely on water injection for NO_X control. Therefore, for those turbines, the monitoring originally required by subpart GG, 40 CFR part 60, is not appropriate. The use of a NO_X CEMS will show compliance with the NO_X standard of subpart GG over all operating ranges. Additionally, many of the units affected by subpart GG are already required to install and certify CEMS for NO_X under other requirements, such as the acid rain monitoring regulation in 40 CFR part 75, or through conditions in various permit requirements. To reduce the burden on these units, we are allowing the use of CEMS units that are certified according to the requirements of 40 CFR part 75. The 40 CFR part 75 testing procedures to certify the CEMS are nearly identical to those in 40 CFR part 60, and 40 CFR part 75 has rigorous quality assurance and quality control standards. Therefore, it is appropriate to allow the use of 40 CFR part 75 CEMS data for subpart GG compliance demonstration. A definition of unit operating hour, which includes the concepts of full and partial operating hours, is needed to clarify how to validate an hour when using CEMS and for the purpose of defining excess emissions and periods of monitor downtime.

B. Optional Fuel-Bound Nitrogen Allowance

The NO_X emission standard in 40 CFR 60.332 includes a NO_X emission allowance for fuel-bound nitrogen. The use of this allowance for fuel-bound nitrogen will be optional upon July 8, 2004. Owners or operators will be able to choose to accept a value of zero for the NO_X emission allowance. The NO_X emission limitations in many State permits are much more stringent than those of subpart GG of 40 CFR part 60. Many turbines are required by their permits to be fired only with pipeline quality natural gas, which is almost free of fuel-bound nitrogen. Therefore, these facilities are not likely to use the fuel-bound nitrogen credit.

C. Frequency of Fuel Nitrogen and Sulfur Content Sampling

Several revisions to the sampling frequency requirements for fuel nitrogen content and fuel sulfur content are being made.

Nitrogen Content for Turbines That Do Not Claim the Allowance for Fuel Bound Nitrogen

We are amending subpart GG of 40 CFR part 60 so that sources are required to monitor the nitrogen content of the fuel being fired in the turbine only if they claim the allowance for fuel-bound nitrogen. For sources that do not seek to use the fuel-bound nitrogen credit, sampling to determine the daily fuel nitrogen concentrations is not required.

Nitrogen and Sulfur Content for Turbines Firing Fuel Oil

The sampling frequency for determining the nitrogen and sulfur content of fuel oil has been amended. Previously for bulk storage fuels, sampling and analysis was required each time new fuel was added. The requirement to sample the nitrogen and sulfur content of the fuel each time fuel is transferred to the storage tank from any other source can be burdensome for a facility if there are one or more large bulk storage tanks which are filled by tanker trucks or isolated from the turbines during the filling process. If the fuel is not fed to the turbines during the filling process, no environmental benefit is gained by sampling every time oil is added from a tanker truck. Similarly, no environmental benefit is gained by sampling a tank which remains isolated from feeding turbines until it is filled. It is less burdensome to allow a tank to be filled completely, regardless of how many tanker trucks it takes, and then drawing a sample of the combined fuel. In the end, this mixture of fuel is what will be fed to the turbines. Thus, we are eliminating the requirement to sample each time new fuel is added and are allowing the use of any of the four sampling options from 40 CFR part 75, appendix D. The four options are as follows: daily sampling, flow proportional sampling, sampling from a unit's storage tank, or sampling each delivery.

Sulfur Content for Turbines Firing Natural Gas

A definition for natural gas has been added to the definitions section. It is consistent with the latest definition in 40 CFR part 72. Owners and operators of turbines that are combusting natural gas are now provided with alternatives to demonstrate that the fuel meets the sulfur content requirement. Sulfur sampling is unnecessary for fuels that qualify as natural gas. As defined in the final rule, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet, which equates to about 0.068 weight percent sulfur, or 680 parts per million by weight (ppmw), or 338 parts per million by volume (ppmv) at 20 degrees Celsius. (The conversion factor from grains of total sulfur per 100 standard cubic foot (gr/scf) to ppmw and percent weight: multiply gr/scf by 3.4×10^3 to get ppmw; divide this product by 10^4 to get percent weight.) When natural gas is combusted, there is no possibility of exceeding the subpart GG, 40 CFR part 60, sulfur limit of 0.8 weight percent or 8000 ppmw.

Sulfur and Nitrogen Content for Turbines Firing Gaseous Fuels Other Than Natural Gas

Units that fire a gaseous fuel that is supplied without intermediate bulk storage, but is not natural gas, must determine and record the sulfur content and (if applicable) nitrogen content once per day. Alternatively, these units may follow one of two custom sulfur sampling schedules outlined in the final rule, or they may develop a custom schedule that is approved by the EPA Administrator. One custom schedule requires daily sampling for 30 consecutive unit operating days. Provided the data indicate compliance, the frequency can then be reduced according to specific criteria. Unit operating day is now defined in 40 CFR 60.331.

Units may also follow a custom schedule based on the 720-hour sulfur sampling demonstration described in 40 CFR part 75, appendix D. Under both schedules, if the margin of compliance is large, the sampling frequency can eventually be reduced to annual. We are codifying these two custom schedules that have routinely been approved under the subpart GG provision that allows sources to develop custom schedules for fuel sampling that must be approved by the EPA Administrator.

D. Steam Injection

Sources that are using water injection currently can monitor the ratio of water to fuel, as well as fuel consumption, to demonstrate compliance with the NO_X standard. We are allowing sources that are using steam injection to monitor the ratio of steam to fuel and fuel consumption to demonstrate compliance. Steam injection is another method of NO_X control, and water and steam injection are the wet methods usually used. Steam injection monitoring is an acceptable type of parametric emission monitoring method.

E. Test Methods for Sulfur Content and Nitrogen Content of Fuel

When subpart GG of 40 CFR part 60 was promulgated, no test methods were specified for monitoring the nitrogen content of the fuel. We are specifying American Society of Testing and Materials (ASTM) D2597–94 (1999), ASTM D6366–99, ASTM D4629–02, or ASTM D5762–02 as acceptable methods for liquid fuels. Under the National Technology Transfer and Advancement Act, we have identified these voluntary consensus standards and are citing them for use. We are not adding any methods for determining the fuel-bound nitrogen content of the fuel being fired for gaseous fuels because none were identified. We do not expect any source owner to use a gaseous fuel with sufficient fuel-bound nitrogen present to claim a credit. Any source owner proposing credit for fuel-bound nitrogen in a gaseous fuel will have to document an acceptable method. We have amended subpart GG to allow the use of most of the methods specified in sections 2.2.5 and 2.3.3.1.2 of 40 CFR part 75, appendix D to determine the total sulfur content of gaseous fuel. The alternative methods for total sulfur provide more flexibility and harmonize with the requirements in 40 CFR part 75. The method ASTM D3031–81 has been deleted from the final rule because it was discontinued by the ASTM in 1990 with no replacement. If the total sulfur content of the fuel being fired in the turbine is less than 0.4 weight percent, we are adding a provision that the following methods may be used to measure the sulfur content of the fuel: ASTM D4084–82 or 94, D5504–01, D6228–98, or the Gas Processors Association Method 2377–86. This provision is consistent with the provision in 40 CFR 60.13(j)(1) allowing alternatives to reference method tests to determine relative accuracy of CEMS for sources with emission rates demonstrated to be less than 50 percent of the applicable standard.

F. Performance Testing

To measure the NO_X and diluent concentration during the performance test, we are adding EPA Method 7E of 40 CFR part 60, appendix A, used in conjunction with EPA Method 3 or 3A of 40 CFR part 60, appendix A, as an acceptable alternative to EPA Method 20. In addition, we are adding ASTM D6522–00 as another alternative to EPA Method 20.

Subpart GG of 40 CFR part 60 previously required the NO_X initial compliance testing to be conducted at four different loads across the unit's operating range. This testing was required because of the difficulty in predicting which operating load will represent worst case conditions when monitoring operational data. Testing, therefore, was done across the operating range to determine the water to fuel ratio and fuel consumption needed to maintain NO_X compliance across the unit's normal operating range. One of the tests was required to be conducted at 100 percent of peak load. We are amending the final rule to allow one test point at 90 to 100 percent of peak load, or the highest load physically achievable in practice. Due to conditions that are beyond the control of the turbine operator, such as ambient conditions, it is often not possible for a turbine to be operated at 100 percent of the manufacturer's design capacity. Therefore, the requirement to test at 100 percent of peak load has been made more flexible.

Another change is that the initial performance test can be performed only at 90 to 100 percent of peak load or the highest physically achievable load in practice, instead of at four different loads, if the owner or operator chooses to use the NO_X CEMS monitoring option. The NO_X CEMS will provide realtime data on NO_X emissions for any given time of operation. This data provides credible evidence which can be used to determine the unit's compliance status on a continuous basis following the initial test. The availability of this continuous information through the use of NO_X CEMS after the initial performance testing justifies testing at a single load for the initial compliance testing. We are also clarifying how data collected during a relative accuracy test audit (RATA) of the NO_X CEMS may be used to demonstrate compliance with the performance tests required by 40 CFR 60.8. The RATA consists of a minimum of nine 21-minute runs using EPA reference test methods, for a total of 189 minutes or just over 3 hours. This amount of sampling accompanied by sampling at multiple traverse points during a RATA provides enough representative emissions data to determine the unit's compliance status.

Finally, a statement has been added to clarify that if the turbine combusts both oil and gas, separate performance testing is required for each type of fuel combusted by the turbine, except for emergency fuel. This is appropriate due to the fact that NO_X emissions vary by fuel type.

G. Measurement After Duct Burner

For sources that are combined cycle turbine systems using supplemental heat, we have added an option that the turbine NO_X emissions may be measured after the duct burner rather than directly after the turbine. No additional NO_X allowance is given. A definition for duct burner has also been added to the definitions section of the final rule. For combined cycle units, there are several concerns with testing and monitoring NO_X at the turbine outlet. For example, it is questionable whether the turbine outlet location is suitable for installation of CEMS. Moreover, due to the high temperature and pressure of the turbine exhaust at that location, it may be difficult to conduct an EPA Method 20 performance test at the turbine outlet of a combined cycle unit. In addition, any combined cycle units that are subject to NO_X CEMS requirements for 40 CFR part 75 or subparts Da and Db of 40 CFR part 60 will most likely have installed the CEMS after the duct burner, on the heat recovery steam generator (HRSG) stack. Another reason to allow measurement of NO_X emissions after the duct burner is that add-on NO_X control systems such as selective catalytic reduction (SCR) are generally located after the duct burner; turbine NO_X performance testing should be conducted after the NO_X control device and would, therefore, include emissions from the duct burner.

H. Option To Not Use International Organization for Standardization (ISO) Correction

We have added an option to not use the ISO correction equation for the following units: Lean premix combustor turbines, units used in association with HRSG equipped with duct burners, and units with add-on emission controls. This option was added based on discussions with the Gas Turbine Association (GTA). The GTA indicated in letters to EPA on April 16, 2002 and May 30, 2002 that the ISO correction equation was not necessary for these units. These letters can be found in the docket. In addition, in response to public comments, we are not requiring the reporting of ambient conditions if you are not using the ISO correction factor.

I. Accuracy of Continuous Monitoring System (CMS) for Fuel Consumption and the Water or Steam to Fuel Ratio

The requirement that the CMS for the fuel consumption and water or steam to fuel ratio for the turbine be accurate to within 5 percent has been removed. The numerical value of water to fuel ratio that serves as a surrogate for the acceptable NO_X concentration is established at each facility. This is accomplished by simultaneously measuring the NO_X concentration and using a CMS to monitor the water or steam to fuel ratio that achieves that NO_X level at various turbine loads at the specific facility during a performance test. This calibration serves to assure that if the water or steam to fuel ratio is maintained above this surrogate value using the same CMS, then acceptable NO_X concentration levels are attained even if the actual numerical value is not correct. Hence, the requirement to be accurate within plus or minus 5 percent is not necessary.

J. Excess Emissions and Monitor Downtime

The excess emission reporting provisions under 40 CFR 60.334 have been amended to include definitions of excess emissions and monitor downtime periods for the various emissions and parameter monitoring requirements. Periods of monitor downtime were not previously defined, so we have added definitions for those periods. New provisions have been added for CEMS and parametric monitoring for certain units; therefore, it is necessary to define the excess emissions and monitor downtime for turbines using these new monitoring options.

K. Other Clarifications

Several other minor clarifications have been made to the final rule. They are as follows: (1) Indicated that the sulfur content standard in 40 CFR 60.333(b) of 0.8 percent by weight is equivalent to 8000 ppmw; (2) clarified the NO_X standard in 40 CFR 60.332(a)(1) to indicate that it is an emission concentration and should be ISO corrected (if required); and (3) clarified the NO_X emission concentration equation in 40 CFR 60.335(b)(1) to indicate it is a concentration instead of a rate and that it is on a dry basis.

III. Summary of Responses to Major Comments

The following sections provide a summary of the major public comments made during the public comment period for the proposed rule. A complete summary of the comments and responses can be found in the Summary of Public Comments and Responses document, which is available from several sources (*see* **ADDRESSES** section).

A. Fuel Sampling/Sulfur Content

Comment: Several commenters wanted to see changes in the fuel sampling strategies. Some commenters wanted to see less sampling requirements, while others wanted more stringent requirements. One commenter felt that eliminating the daily fuel total sulfur content sampling requirement is not environmentally beneficial, and creates a situation where the emission of sulfur compounds is presumptive with no measured foundation. Other commenters felt that EPA should provide additional options to sampling for nitrogen and sulfur content in fuel oil, particularly when the unit only combusts fuel oil on a limited basis.

Response: We did not make any changes to the fuel sampling requirements in the final rule. The amendments did not eliminate any requirements for natural gas sulfur content sampling. Rather, they provide optional (not mandatory) relief from monitoring the sulfur content of natural gas. Natural gas is defined in the final rule as having a sulfur content of 20 grains or less of total sulfur per 100 standard cubic feet, which equates to 0.068 weight percent sulfur, or 680 ppmw. When natural gas is combusted, there is no possibility of exceeding the subpart GG of 40 CFR part 60 sulfur limit of 0.8 weight percent.

The commenter is not correct in asserting that this new provision is ''presumptive with no measured foundation.'' The final rule requires the owner or operator to document that the fuel meets the definition of natural gas in order to obtain the regulatory relief.

In regards to fuel oil, the revisions to § 60.334(i)(1) provide owners and operators with many options for scheduling of fuel oil sampling. They may sample on a per delivery basis; therefore, daily sampling is not a requirement. In addition, failure to sample deliveries of fuel oil if no fuel oil has been combusted is not an excess emission if one of the other schedules has been retained. An owner or operator may utilize flow proportional sampling, which would require samples only if fuel oil is being combusted. Owners and operators are not precluded from taking one sample for the day for all units operated during an official ''unit operating day.'' No changes have been made to the proposed regulatory text in response to this comment.

B. Monitoring

Comment: Several comments were received on the proposed continuous monitoring provisions. Commenters stated that EPA should withdraw the optional continuous emission monitoring provisions under § 60.334(c), (e), and (f) for turbines that do not use water or steam injection to comply with the applicable NO_X emission standards.

One commenter requested that EPA make clear that the choice of whether to use a NO_X CEMS is entirely at the discretion of the source owner or operator, even in those cases where a NO_X CEMS is installed. The commenter also requested that EPA make clear that nothing in the final rule is intended to impose new requirements, or to alter or prevent other determinations regarding the adequacy of monitoring to comply with subpart GG of 40 CFR part 60. Some commenters recommended that EPA make clear in the final rule or preamble that (1) alternatives approved by State and local agencies under State authority, or delegation of authority from EPA are also valid, and (2) these amendments do not impose any new requirements, or require revision of existing permits, but simply provide several pre-approved options for sources that do not want to seek case-by-case approval.

Another commenter recommended the addition of language to § 60.334(c) indicating that existing turbines under subpart GG of 40 CFR part 60 without water or steam injection that are not required to implement continuous direct or indirect NO_X monitoring under their current approvals may continue to operate under the provisions of their current approvals. The commenter stated that an annual NO_X stack test could serve as an appropriate alternative to a NO_X CEMS or parametric monitoring for an existing subpart GG turbine with low annual utilization (< 1500 hours per year). For a small baseload turbine, an existing quarterly stack testing requirement would be an appropriate CEMS or parametric monitoring alternative.

Four commenters stated that the proposed revisions would wrongly impose significant new requirements for ongoing NO_X compliance monitoring on mid-range stationary gas turbines and turbines in natural gas transmission. One commenter gathered over 100 permits, including construction and title V permits, for turbines subject to the NSPS. Examination of the gathered permits showed that continuous monitoring of emissions or parameters has typically not been required. The commenters expressed opposition to the provisions proposed in § 60.334(c), which they believed fail to address existing mid-range turbines subject to the NSPS because the vast majority of these turbines have neither CEMS nor an EPA-approved petition for alternative monitoring. Even natural gas transmission turbines with emission limits dramatically lower than the current NSPS limits are not typically required to install CEMS. Additionally, lean premix turbines have little possibility of exceeding the NSPS emission limit as it currently stands. The commenters requested that EPA revise § 60.334(c) to clearly state that monitoring requirements included in existing permits should not be revised as a result of this rulemaking. The commenters also did not support the provisions proposed in § 60.334(e) and (f) because the commenters believed the provisions would impose significant new regulatory requirements on new NSPS turbines in natural gas transmission service and other mid-range units. In addition, one commenter stated that in the memo in the docket, EPA ignored the costs for the significant new requirements which would be imposed, since most of the natural gas transmission and other mid-range units do not currently have CEMS installed. Therefore, in their opinion, EPA has failed to estimate the true impacts of the final rule, including the impacts related to increased monitoring, recordkeeping and reporting requirements for their industry. The commenters recommended that EPA write § 60.334(e) and (f) so that they do not impose CEMS or continuous parameter monitoring requirements on owner/operators that are not otherwise required to use CEMS or continuous parametric monitoring, and to consider the current Agency approved NO_X compliance monitoring techniques that are used by the natural gas transmission industry for NSPS turbines as alternatives to the continuous monitoring provisions included in part 75.

Two commenters stated the EPA should not rely on the May 31, 1994 memorandum from John Rasnic (EPA Applicability Determinations Index, Control No. 9700124) regarding compliance monitoring for turbines that use technology other than water injection as the basis for the proposed subpart GG revisions. One commenter requested that the 1994 memorandum be formally withdrawn by the agency.

Two commenters suggested that if EPA intends to impose new monitoring requirements for NSPS turbines, EPA should issue a new proposal with that intent expressly stated. One commenter further stated that the proposal should include the full range of compliance monitoring for natural gas combustion turbines, as currently approved by EPA in existing permits for NSPS turbines, and should be performed in conjunction with the revisions of the NSPS emission standards.

Response: We have clarified in the preamble that nothing in the final rule amendments is intended to impose new requirements for turbines constructed between 1977 and the effective date of the final rule amendments. Instead, we have described a number of acceptable continuous compliance methodologies (*e.g.*, the use of CEMS) for these units. We have added language to the preamble and rule which clarifies that continuous compliance methodologies already approved by EPA or by the local permitting authority are still valid. We do not agree that these revisions would impose new requirements for these turbines. We have ensured that the regulatory language is clear with respect to the use of CEMS as an option, and also made sure that any previously approved methods are still valid. Hence, for existing turbines covered under subpart GG of 40 CFR part 60, there are no compliance costs associated with these amendments.

Comment: One commenter requested that EPA provide the option of monitoring either O_2 or carbon dioxide (CO_2) as a diluent when using a NO_X CEMS in § 60.334(b), in the interest of consistency with 40 CFR part 75.

Response: We agree that it is acceptable to make the required dilution correction with data from a CO_2 monitor. In the final rule, § 60.334(b) has been revised to include the CO_2 correction procedure from Method 20. The CO_2 readings must be converted to equivalent O_2 using equations F–14a or F–14b in 40 CFR part 75, appendix F.

Comment: One commenter requested that EPA clarify whether the revised subpart GG, 40 CFR part 60, allows application of the 40 CFR part 75 O_2 (or CO_2) Diluent Cap provisions. This provision allows substitution of an O_2 value of 19 percent for any hour where O_2 is measured at levels greater than 19 percent.

Response: We agree that it is acceptable to provide a diluent cap procedure for reducing CEMS data. This comment has been incorporated. Section 60.334(b)(3)(i) of the final rule allows the diluent cap value of 19.0 percent O_2 to be used to calculate the NO_X emissions whenever the quality-assured hourly O_2 concentration measured by the O_2 monitor (or calculated from a CO_2 monitor reading) is greater than 19.0 percent O_2. No alternative petition will be required.

Comment: One commenter stated that EPA should amend the monitoring provisions of § 60.334(a) to clarify that monitoring applies only to those turbines that must use water or steam injection to control NO_X emissions ''to comply with the NO_X standards under § 60.332(a).'' The commenter noted that some turbines may be able to comply with the subpart GG, 40 CFR part 60, NO_X standard uncontrolled, but need water or steam injection to comply with a more stringent NO_X standard.

Response: We do not agree with the commenter's suggested clarification that the monitoring requirements should apply only to turbines that use steam or water injection to control NO_X emissions to comply with the NO_X standards under § 60.332(a). Water injection is mentioned in § 60.334(a) because it was the only emission control technology available for turbines when subpart GG, 40 CFR part 60, was proposed back in 1977. As we have done in the past, the use of alternative continuous monitoring methods may be approved by EPA on a case-by-case basis for turbines that do not use water injection to control NO_X. Although a turbine may be able to meet the NO_X emission standard with other control technologies, continuous monitoring is needed to ensure that the emission limit is being met at all times.

Comment: One commenter expressed the view that the proposed rule failed to address the use of NO_X concentration data that have been ''bias adjusted'' under 40 CFR part 75. The commenter stated that EPA should acknowledge that sources cannot be required to use bias adjusted data, as was done in 40 CFR part 60, subpart Da. The commenter noted that some turbines with emissions significantly lower than their subpart GG, 40 CFR part 60, limit may prefer to simplify their reporting by utilizing the same bias adjusted data for subpart GG and 40 CFR part 75 and suggested the EPA make reporting of bias adjusted data for ''excess emissions'' monitoring optional.

Response: The commenter's suggestion was not incorporated. Combustion turbines covered under 40 CFR part 75 that use CEMS for NO_X compliance are required to monitor and report the NO_X emission rate in pounds per million british thermal units (lb/MMBTU) on an hourly basis. To achieve this, a NO_X-diluent CEMS is used to continuously measure the NO_X concentration (ppm) and either the percent O_2 or percent CO_2. These measured gas concentrations are used to calculate the required hourly NO_X emission rates. Under 40 CFR part 75, the relative accuracy test audit (RATA) of a NO_X-diluent CEMS is performed on a lb/MMBTU basis. If, during the RATA, the NO_X emission rates calculated from the CEMS data are biased low with respect to the emission rates derived from the EPA reference methods, a bias adjustment factor must be applied to the subsequent hourly NO_X emission rates. Since the bias adjustment factor is applied to the lb/MMBTU NO_X emission rates and not to the NO_X ppm values, and since diluent concentration data are never adjusted for bias under 40 CFR part 75, there is no need to mention bias-adjusted data in subpart GG of 40 CFR part 60. The subpart GG emission limits are in units of ppm of NO_X, corrected to 15 percent O_2. Therefore, any 40 CFR part 75 NO_X concentration or O_2 data used to assess compliance with these emission limits would not be bias-adjusted.

Comment: One commenter urged EPA to use its $PM_{2.5}$ precursor foundation (67 FR 39602, June 10, 2002) to impose an ammonia (NH_3) CEMS obligation on all gas turbines that utilize SCR as NO_X control, with quarterly reporting for NO_X and NH_3 emissions.

Response: Since ammonia is not regulated under subpart GG, 40 CFR part 60, we do not support adding a continuous monitoring requirement for ammonia to the NSPS.

Comment: Two commenters stated that some turbines in the gas transmission industry are diffusion flame combustors, yet are small (1200 HP, 11 MMBTU/hr). The commenter feels that since the manufacturer guarantee is 100 ppm while the NSPS emission limit is 150 ppm NO_X, that a mandatory CEMS requirement is inappropriate and imposes an unreasonable regulatory burden.

Response: As was stated in the preamble, we did not intend to impose any new requirements on existing turbines covered subpart GG, 40 CFR part 60, through the promulgation of the final rule. We have clarified in the final rule that (1) alternatives approved by State and local agencies under State authority, or delegation of authority from EPA are also valid, and (2) these amendments do not impose any new requirements, or require revision of existing permits, but simply provide several pre-approved options for sources that do not want to seek case-by-case approval.

Comment: One commenter wanted EPA to explicitly reference appendix F of 40 CFR part 60, regarding quality assurance procedures for NO_X CEMS.

Response: Continuous emission monitoring systems are used as an alternative to water to fuel ratio monitoring, to identify and report periods of excess emissions, and, therefore, appendix F, procedure 1, 40 CFR part 60, is not mandatory. Section 60.334(b)(4) has been removed.

Comment: Three commenters did not support the proposed changes presented in § 60.334(f), which address continuous parameter monitoring as an alternative to CEMS for new turbines that do not use steam or water injection to control NO_X emissions. The commenters noted that continuous parameter monitoring is not consistent with monitoring typically required for mid-range stationary gas turbines, including turbines used in natural gas transmission service, and would impose significant new regulatory requirements on these. Commenters recommended that EPA write the provisions in the final rulemaking to effect EPA's original intent of codifying the option to use continuous parameter monitoring, when otherwise required for other reasons such as 40 CFR part 75, without imposing significant new requirements on other owners or operators. The commenter also recommended that EPA explicitly state in the preamble that permitting authorities, under title V periodic monitoring or other programs, are not restricted to continuous monitoring of emissions or parameters and may continue to consider the full range of compliance monitoring options for gas-fired turbines. One commenter supported EPA's goal of allowing owners or operators the flexibility to use data from continuous parameter monitoring already required for other reasons to demonstrate compliance with the NSPS. However, the commenter does not support a mandatory requirement for continuous parameter monitoring and requests that EPA withdraw § 60.334(f) from the direct final and proposed rules.

In addition, two commenters stated that new lean premix turbines have little possibility of exceeding the NSPS emission limit as it currently stands.

Indeed, verification of lean premix combustion ensures NO_X emissions at levels far below the current NSPS emission limit. Equally, information about operation outside of lean premix does not provide meaningful information about whether a unit has failed to comply with the current NSPS emission limit.

Response: As was stated in the preamble, we did not intend to impose any new requirements through the promulgation of the final rule. We have clarified in the final rule and preamble that the amendments do not impose any new requirements but simply provide several pre-approved options for sources that do not want to seek case-by-case approval.

In regard to the comment that new lean premix turbines are able to comply with the current emission limit with little possibility of exceeding the standards, we plan to amend the emission limitations in subpart GG, 40 CFR part 60, as part of an upcoming rulemaking.

Comment: One commenter opposed and requested the removal of the parameter monitoring plan requirement proposed in § 60.334(g). They further stated that it does not streamline the differences between subpart GG, 40 CFR part 60, and 40 CFR part 75 appendix E requirements. According to the commenter, appendix E adequately addressed this issue. One commenter requested that the provisions in § 60.334(g), which address the use of performance test data to establish acceptable parameter ranges, be written to provide the opportunity for owners and operators to establish and/or adjust operating parameter limitations based on performance tests, engineering analysis, design specifications, manufacturer recommendations or other applicable information, such as a performance test on a similar unit. Since gas transmission units are load following, it may not be possible to operate at specific load conditions at the predetermined time scheduled for the performance test, and maximum and minimum load condition emissions may not be seen during the performance test. A similar unit, however, can exhibit representative emissions for developing parameter limitations.

Response: The requirement to develop and maintain a parameter monitoring plan has been retained in the final rule. For units that use continuous parameter monitoring to assess compliance with the emission limits under subpart GG, 40 CFR part 60, it is essential for the owner or operator to clearly identify the monitored parameters and their acceptable ranges, and to provide the technical basis for selecting those parameters and ranges. Section 60.334(g) of the final rule allows the owner or operator to supplement the parametric data recorded at the time of the initial performance test with other types of information, in order to establish the appropriate parametric ranges and values.

In response to the comment about units under appendix E, 40 CFR part 75, § 60.334(f) and (g) of the final rule make it clear that if the owner or operator performs the parametric monitoring described in section 2.3 of appendix E, 40 CFR part 75, and maintains the quality assurance (QA) plan described in section 1.3.6 of 40 CFR part 75, appendix B, this will satisfy the requirements of subpart GG of 40 CFR part 60. For the sake of completeness, for low mass emissions (LME) units, the final rule also allows the owner or operator to use the QA plan described in § 75.19(e)(5) to satisfy the parameter monitoring plan requirements of subpart GG.

Comment: Two commenters stated that continuous parameter monitoring is not appropriate for new diffusion flame turbines subject to NSPS. Some models of diffusion flame combustors are installed for the natural gas industry for which there are no predictive emission monitoring systems available. Development of one would impose an unreasonable burden on the industry.

Response: Predictive emission monitoring systems (PEMS), are very different from the parameter monitoring option that we have added to the final rule. Continuous parameter monitoring refers to the monitoring of operating conditions or parameters, such as turbine exhaust temperature, compressor discharge pressure, or any others which may be indicative of the unit's NO_X formation characteristics. Predictive emission monitoring systems, on the other hand, predict actual emission rates or concentrations from operating parameters that affect NO_X formation. Parameter monitoring oversees operating parameter boundaries, while PEMS measure emission rates or concentrations. Adding the option to continuously monitor parameters that are indicative of the unit's NO_X formation characteristics would not impose an unreasonable burden on the industry. No changes have been made from the proposed rule to the final rule to address this comment.

Comment: One commenter opposed the 4-hour averaging period to determine compliance. The commenter stated that EPA should base averaging times on the stated permit conditions of a Prevention of Significant Deterioration/New Source Review (PSD/NSR) permit issued by the permitting authority and that subpart GG, 40 CFR part 60, should remain silent on this issue other than the time it takes to conduct the required compliance stack testing.

Response: We do not agree with the commenter. The 4-hour averaging period has been retained in the final rule. The commenter is incorrect in asserting that subpart GG, 40 CFR part 60, should be silent on the issue of the averaging period for excess emission reporting. Each NSPS subpart that requires excess emission monitoring and reporting with respect to a particular emission limit must specify an averaging period. If a subpart GG turbine is subject to another more stringent NO_X emission limit with a different averaging period than subpart GG (*e.g.* a permit limit), and if the unit's operating permit requires excess emission reporting with respect to that limit, then two separate excess emission reports must be filed, *i.e.*, one to satisfy subpart GG requirements and the other to meet the permit requirement.

Comment: One commenter did not believe that EPA's attempt to distinguish between ''excess emissions'' and ''deviations'' is necessary since neither are violations under subpart GG, 40 CFR part 60. The commenter was also concerned that the choice of the term ''deviation'' could cause confusion in the context of title V permits and State Implementation Plans (SIP) and suggested the EPA either continue to use the term ''excess emissions'' for all reported parameters under subpart GG, or follow the terminology adopted in the Compliance Assurance Monitoring rule at 40 CFR part 64, which refers to parameter exceedances as ''excursions.''

Response: We agree with the commenter that it is not necessary to distinguish between ''deviations'' and ''excess emissions.'' Both terms represent an averaging period during which a monitored parameter exceeds the limit specified in the final rule. Therefore, use of the term ''deviation'' in addition to ''excess emissions'' would be redundant. The final rule does not use the term ''deviation.''

Comment: One commenter requested clarification on § 60.334(j)(2), which says that periods of excess emissions and monitor downtime end on the date and hour of the next valid sample. The commenter stated that EPA should clarify that the period of excess emissions and/or monitor downtime from the start date to the next valid sample includes only unit operating hours.

Another commenter requested that the 4-hour rolling averaging period for NO_X emissions extend backward three operating hours, not three quality assured operating hours. The commenter noted that the standard CEMS vendor software is configured to look back a fixed number of calendar or on-line hours, but not quality assured hours.

Response: We agree with both commenters, and have written the final rule accordingly. ''Quality assured'' has been removed when used in reference to the rolling averaging period.

Comment: Two commenters requested clarification on the issue of compliance during startup and shutdown. One commenter asked whether startup and shutdown hours can be excluded from the 4-hour NO_X CEMS rolling averages used for compliance determination. The commenter also asked how site specific startup and shutdown periods should be established and whether the site can simply use manufacturer's recommended durations. One commenter stated that EPA should modify § 60.334(j)(1)(iii)(A) to add language clarifying that the average excludes emissions from startup, shutdown, and malfunctions.

Two commenters remarked that the requirement in § 60.334(j)(1)(i)(A) that ''any unit operating hour in which no water or steam is injected into the turbine shall also be considered a deviation'' does not appear to exempt startup or shutdown transients. One commenter said that any gas turbine equipped with steam or water injection for NO_X control would always have a deviation during startup and shutdown transients. According to the commenter, steam or water injection is usually initiated between 20 to 50 percent of base load during startup and is likewise discontinued during the shutdown transient. One commenter recommended revising the wording of the last sentence of the section to read as follows: ''Any unit operating hour in which no water or steam is injected into the turbine shall also be considered a deviation *for purposes of reporting periods of startup, shutdown, and malfunction.*''

Response: In response to these comments, § 60.334(j) of the final rule has been written to clearly state that excess emissions must be recorded during all periods of unit operation, including startup, shutdown and malfunction. All excess emissions are reported and categorized. Note that the final rule does not use the term ''deviation.'' Startup and shutdown are two of those categories. 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, § 60.11(d) requires affected units to be operated in a manner consistent with good air pollution control practice for minimizing emissions. Excess emission data may be used to determine whether a facility's operation and maintenance procedures are consistent with § 60.11(d).

C. Test Methods and Procedures

Comment: One commenter requested that EPA allow performance tests to be conducted in the normal operating range of the gas turbine and allow for testing units that cannot be operated at ''peak load'' due to process constraints. The commenter suggested that instead of 90 to 100 percent of peak load, the owner or operator could test at the highest achievable load point if 90 to 100 percent of peak load could not physically be achieved in practice.

Response: The final rule incorporates the commenter's suggested revisions to § 60.335(b)(2). It is reasonable to make allowance for units that are not physically capable of attaining 90-to-100 percent of peak load.

Comment: One commenter suggested that if the permitted operating range of a turbine is sufficiently narrow, the required number of load levels for performance testing should be appropriately reduced. The commenter suggested that a minimum load level spacing of 20 percent be established.

Response: The requirement for four points for performance testing is necessary. The purpose of the data is to establish a water to fuel ratio. Two points are not enough to establish a statistically relevant relationship. Thus, we have not made any changes from the proposed rule to the final rule related to this comment.

Comment: Two commenters noted that the reference in § 60.335(a) to the procedures in section 6.5.6.3(a) and (c) of 40 CFR part 75, appendix A, should be changed to section 6.5.6.3 (a) and (b). Similarly, one commenter requested that the single measurement point identified in sections 6.5.6(b)(4) and 6.5.6.3(b) of 40 CFR part 75, appendix A, be added to the final rule. The commenter noted that the stratification testing procedure for a single measurement point is identical to the long and short measurement lines and the acceptance criteria for a single measurement point is more stringent.

Response: We agree with the commenter that measurement at a single point is appropriate in certain situations. In the interest of consistency with 40 CFR part 75, we have indicated in the final rule that data collected following section 6.5.6.1 can be used. Also, we have written the initial performance test requirements in § 60.335(a) to reflect that this option is available. However, because recently proposed revisions to Method 7E have more restrictive criteria at lower concentrations than those in section 6.5.6.3 of 40 CFR part 75, it is not appropriate to allow consistency in this case. Therefore, we have removed reference to section 6.5.6.3 of 40 CFR part 75 in the final rule. It is still possible to use the same data and choose the more restrictive number of sampling locations.

Comment: Two commenters recommended that a subparagraph be added to § 60.335(a) to clearly distinguish requirements for owners and operators that opt for using ASTM D6522–00 or EPA Method 7E instead of Method 20. One commenter suggested that the following should be appended to paragraph (a): ''Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.''

The commenters noted that much of the new language EPA has added to the test methods and procedures under § 60.335(a) pertains to RATA and as these requirements are being applied to performance testing, any reference to a RATA is inappropriate and should be replaced with ''performance testing.''

Response: We agree with the commenter that requirements for those opting to use ASTM D6522–00 and/or EPA Method 7E should be clarified. Section 60.335(a) has been modified accordingly. We also agree that references to a RATA in § 60.335(a) should be deleted and replaced with ''performance testing'' and have written the final rule accordingly.

Comment: Two commenters requested that EPA revise § 60.335(a), which specifies that owners or operators choosing to use EPA Methods 7E and 3A (or 3) for NO_X performance testing must perform a stratification test for NO_X and diluent under 40 CFR part 75, appendix A, section 6.5.6.1(a)–(e) in order to determine if subsequent RATA testing will occur along a short or long reference method measurement line. One commenter appreciated EPA's proposal to add the option of using a short measurement line, but did not understand why a source that chooses to use the long reference measurement line would need to perform the stratification test. One commenter stated that if a source agrees to use the most stringent options (*i.e.*, the long measurement line), it would seem unnecessary to require a stratification check.

Response: Section 60.335(a) applies to a performance test, not a RATA. We agree that if a source provides initial documentation that stratification does not exist, it is appropriate to have a reduced number of sampling points. We also agree that a source can skip the stratification test and default to using a multi-hole probe, and § 60.335 has been modified accordingly. However, because it is possible to have spatial stratification due to several reasons such as ammonia injection that would not be accounted for with the long measurement line, we are requiring documentation that stratification does not exist. We have also indicated that the use of data following section 6.5.6.1 of 40 CFR part 75 can be used. In addition, we have reserved a paragraph in § 60.335(a)(5)(i)(A) that will give the option of using stratification testing protocols that were proposed for Methods 7E and 3A in a separate **Federal Register** action.

D. ISO Correction

Comment: Two commenters recommended the removal of the ISO correction calculation. According to one commenter, the calculation is not practical for the modern turbine, and incorporation of the ISO correction factor within a CEMS requires burdensome administrative changes and unnecessary certification. As an alternative to removal of the ISO correction calculation, the commenter expressed support for making the ISO correction optional for specific gas turbines.

Another commenter recommended that EPA harmonize subpart GG, 40 CFR part 60, with 40 CFR part 75 monitoring requirements, eliminating any requirement to correct to ISO conditions, instead correcting to 15 percent O_2. The commenter also said that EPA should recognize the use of water injection as an add-on emission control device. The commenter noted that many lean premix units operate in limited use diffusion flame mode with water injection for emissions control and recommended that EPA recognize these dual-fuel units as lean premix where the primary fuel is natural gas combusted in lean premix mode. Further, they suggested that EPA exempt from ISO correction units that employ water injection when monitored in accordance with 40 CFR part 75 requirements. Similarly, one commenter recommended that diffusion flame units using water injection to control NO_X be exempt from the ISO data correction. Their rationale is that water injection cools the flame temperature to a level where NO_X is no longer primarily produced by thermal processes (much like lean premix, where the majority of NO_X is not produced thermally).

One commenter suggested that any turbine equipped with a NO_X CEMS be provided the option of not applying the ISO correction, irrespective of its design or configuration.

One commenter observed that the use of the ISO correction equation has no technical basis for gas turbines with lean premix combustors or for diffusion flame combustors with water or steam injection and NO_X levels significantly below the subpart GG, 40 CFR part 60, levels of 75 ppm.

Response: No adequate rationale was provided for exempting all turbines from the ISO correction factor. The ISO correction factor was initially developed for diffusion flame units, and no rationale has been provided for making it optional for these units. The ISO correction factor continues to be appropriate for diffusion flame units and water or steam injected units. The need for the ISO correction factor will continue as we begin the process of revising the emission limits in subpart GG, 40 CFR part 60, in the near future. We have also clarified in the final rule that when a unit is capable of using both lean premix and diffusion flame modes, it is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

Comment: Two commenters recommended that EPA remove the requirement to record ambient conditions when operating a turbine. One commenter stated that this requirement is burdensome and unnecessary and adds an administrative requirement that has no bearing on the environment. One commenter stated that for turbine units that are exempt from applying the ISO correction or which apply worst case ambient conditions to make the ISO corrections, the reporting of ambient conditions is unnecessary and represents a significant burden, since they are not collecting this data on-site.

Response: The ambient condition data is not used for any purpose other than the ISO correction. Therefore, we agree that the requirement in the proposed § 60.334(j)(1)(i)(C) and (iii)(C) to report the ambient conditions is unnecessary for those turbines for which the ISO correction is optional under § 60.335(b)(1). Also, reporting of ambient conditions is not necessary if an owner or operator chooses to calculate and apply a worst case ISO correction factor as specified in § 60.334(b)(3)(ii). Reporting of ambient conditions is still necessary for turbines that are required to use the ISO correction factor and do not opt to use a worst case ISO correction factor. We have written the final rule accordingly.

E. Emission Standards

Comment: A few commenters suggested revising the emission limits for sulfur and nitrogen in subpart GG, 40 CFR part 60.

Response: We will address emission limits in a future rulemaking amending subpart GG. We have not amended the emission limitations at this time.

F. Duct Burners

Comment: One commenter expressed the opinion that the option to measure gas turbine NO_X emissions in the exhaust stream after the duct burner rather than directly after the turbine is not viable as written because it does not account for the additional NO_X contribution from the duct burner. The commenter stated that the final rule should be written to provide for the duct burner NO_X contribution.

Response: The purpose of the final rule amendment was to allow owners and operators the flexibility of making one measurement downstream of the duct burner since many turbines are able to comply with the NO_X limit even with the potential NO_X contribution resulting from the duct burner. Accounting for the NO_X contribution from the duct burner would require two NO_X measurements, which clearly defeats the purpose of the amendment. Furthermore, owners and operators still have the option of simply measuring NO_X emissions in the turbine exhaust, prior to the duct burner. For these reasons, we disagree with the commenter and have not made any changes from the proposed rule to the final rule with respect to this provision.

IV. Environmental and Economic Impacts

The final rule amendments will not have any significant economic or environmental impacts. The amendments have been written primarily to codify routine testing and monitoring alternatives that have previously been approved by us. We are not introducing any new emission limitations, control requirements, or monitoring requirements. We are attempting to reduce the testing, monitoring, and reporting burden by harmonizing with the requirements of 40 CFR part 75, since many gas turbines are subject to it as well as subpart GG of 40 CFR part 60.

V. 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.

It has been determined that the final rule is not a ''significant regulatory action'' under the terms of Executive Order 12866 and is therefore not subject to EO 12866 review.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. 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 are listed in 40 CFR part 9 and 48 CFR chapter 15.

The amendments contain no changes to the information collection requirements of the current NSPS that would increase the burden to sources, and the currently approved OMB information collection requests are still in force for the amended rule. Some amendments in the final rule, such as allowing the use of CEMS to measure NO_X emissions, are provided as an option to sources, and should reduce burden to those sources who already have a CEMS in place for other regulatory reasons, such as the Acid Rain requirements in 40 CFR part 75. Other amendments, such as the allowance of parametric monitoring in place of water to fuel ratio monitoring, do not result in additional recordkeeping and reporting requirements beyond those already required.

C. Regulatory Flexibility Analysis

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with the final rule.

For purposes of assessing the impacts of the 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, or fewer than 4 billion kW-hr per year of electricity usage, depending on the size definition for the affected North American Industry Classification System (NAICS) code; (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 six NAICS codes may 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 (SBA) size standards (13 CFR part 121).

After considering the economic impacts of the final rule on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant adverse economic impact on small entities, since the primary purpose of the regulatory flexibility analysis is to identify and address regulatory alternatives ''which minimize any significant economic impact of the proposed rule on small entities.'' 5 U.S.C. §§ 603 and 604. Thus, an agency may conclude that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect on all of the small entities subject to the rule. Our conclusion that today's final rule will relieve regulatory burden on small entities is based primarily upon the estimated cost savings to turbine owners and operators as a result of the revisions to 40 CFR part 60, subpart GG, that are presented earlier in this preamble. These cost savings will be experienced by turbines owned and operated by small entities as well as large ones. Using the existing combustion turbines inventory as a measure of which industries may install new turbines in the future, presuming the existing mix of current combustion turbines is a good approximation of the mix of turbines that will be installed and affected by the final rule up to 2007, 2.5 percent of new turbines overall will likely be owned and operated by small entities. Of these entities, a majority of these are owned and operated by small communities.

For more information on the results of the analysis of small entity impacts, please refer to the economic impact analysis in the docket.

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 one 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.

The EPA has determined that the final rule amendments contain 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 one year. Thus, the amendments are not subject to the requirements of sections 202 and 205 of the UMRA. In addition, EPA has determined that the amendments contain 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 amendments are 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. Today's action codifies alternative testing and monitoring procedures that have routinely been approved by EPA. There are minimal, if any, impacts associated with this action. Thus, Executive Order 13132 does not apply to the final rule amendments.

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 gas 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 Risks 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.

We interpret Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. The final rule is not subject to Executive Order 13045 because it is based on technology performance and not on health or safety risks.

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

The final rule is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866.

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.

These final rule amendments involve technical standards. The EPA cites the following methods in the final rule amendments: EPA Methods 1, 3, 3A, 7E, and 20 of 40 CFR part 60, appendix A; and PS 2 and 3 of 40 CFR part 60, appendix B. In addition, these final rule amendments cite the following standards that are also incorporated by reference (IBR) in 40 CFR part 60, section 17: ASTM D129–00, ASTM D1072–80 or –90 (Reapproved 1999), ASTM D1266–98, ASTM D1552–01, ASTM D2597–94 (Reapproved 1999), ASTM D2622–98, ASTM D3246–81 or –92 or –96, ASTM D4084–82 or –94, ASTM D4294–02, ASTM D4468–85 (Reapproved 2000), ASTM D4629–02, ASTM D5453–00, ASTM D5504–01, ASTM D5762–02, ASTM D6228–98, ASTM D6366–99, ASTM D6522–00, ASTM D6667–01, 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 PS 3. The search and review results have been documented and are placed in the docket (OAR–2002–0053) for the final rule amendments.

One voluntary consensus standard was identified as an acceptable alternative to the EPA methods specified in the final rule amendments. The standard ASTM D6522–00, ''Standard Test Method for the 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,'' is cited in the final rule amendments as an acceptable alternative to EPA Methods 3A, 7E, and 20 for identifying nitrogen oxide and oxygen concentration when the fuel is natural gas. This standard, ASTM D6522–00, has been also IBR in 40 CFR part 60, section 17.

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

Sections 60.334 and 60.335 of the final rule amendments to subpart GG, 40 CFR part 60, discuss the EPA testing methods, performance specification, and procedures required. Under §§ 63.7(f) and 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 the EPA testing methods, performance specifications, or procedures.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 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. The EPA will submit a report containing the 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 final rule in the **Federal Register**. The final rule is not a ''major rule'' as defined by 5 U.S.C. 804(2).

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: June 24, 2004.

Michael O. Leavitt,

Administrator.

■ For the reasons stated in the preamble, title 40, chapter I, part 60, of the Code of Federal Regulations is amended to read 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:
■ a. Removing and reserving paragraph (a)(38);
■ b. Revising paragraph (a) introductory text;
■ c. Revising paragraph (a)(8);
■ d. Revising paragraph (a)(15);
■ e. Revising paragraph (a)(18);
■ f. Revising paragraph (a)(20);
■ g. Revising paragraph (a)(33);
■ h. Revising paragraph (a)(43);
■ i. Revising paragraph (a)(50);
■ j. Adding paragraphs (a)(65) through (a)(75); and
■ k. Adding paragraph (m).

The revisions and additions 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.

* * * * *

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

* * * * *

(15) 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 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).

* * * * *

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

* * * * *

(33) 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).

* * * * *

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

* * * * *

(50) 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).

* * * * *

(65) 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).

(66) 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).

(67) 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).

(68) 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).

(69) 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).

(70) 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).

(71) 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).

(72) 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).

(73) 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).

(74) 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).

(75) 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).

* * * * *

(m) This material is available for purchase from at least one of the following addresses: The Gas Processors Association, 6526 East 60th Street, Tulsa, OK, 74145; or Information Handling Services, 15 Inverness Way East, PO Box 1154, Englewood, CO 80150–1154. You may inspect a copy at EPA's Air and Radiation Docket and Information Center, Room B108, 1301 Constitution Ave., NW., Washington, DC 20460.

(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).

Subpart GG—[Amended]

■ 3. Section 60.331 is amended by adding paragraphs (s) through (y) to read as follows:

§ 60.331 Definitions.

* * * * *

(s) *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.

(t) *Excess emissions* means a specified averaging period over which either:

(1) The NO_X emissions are higher than the applicable emission limit in § 60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in § 60.333; 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.

(u) *Natural gas* means a naturally occurring fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 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.

(v) *Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas 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.

(w) *Lean premix stationary combustion turbine* means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) *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. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) *Unit operating day* means a 24-hour period between 12:00 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.

■ 4. Section 60.332 is amended by:

■ a. Revising the terms to the equations in paragraphs (a)(1) through (2);

■ b. Redesignating paragraph (a)(3) as (a)(4);

■ c. Revising newly designated paragraph (a)(4); and

■ c. Adding a new paragraph (a)(3).

The revisions and additions read as follows:

§ 60.332 Standard for nitrogen oxides.

(a) * * *

(1) * * *

Where:

STD = allowable ISO corrected (if required as given in § 60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(2) * * *

Where:

STD = allowable ISO corrected (if required as given in § 60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this seciton is optional. That

is, the owner or operator may choose to apply a NO_X allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NO_X emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under § 60.8 as follows:

Fuel-bound nitrogen (percent by weight)	F (NO_X percent by volume)
N ≤ 0.015	0
0.015 < N≤ 0.1	0.04(N)
0.1 < N ≤ 0.25	0.004+0.0067(N–0.1)
N > 0.25	0.005

Where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by § 60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the **Federal Register**.

* * * * *

■ 5. Section 60.333 is amended by revising paragraph (b) to read as follows:

§ 60.333 Standard for sulfur dioxide.

* * * * *

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

■ 6. Section 60.334 is amended by:
■ a. Revising paragraphs (a) and (b);
■ b. Redesignating paragraph (c) as paragraph (j);
■ c. Adding a new paragraph (c);
■ d. Adding paragraphs (d) through (i);
■ e. Revising newly designated paragraph (j) introductory text, (j)(1) and (j)(2); and
■ f. Adding paragraph (j)(5).

The revisions and additions read as follows:

§ 60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO_X emissions shall 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.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_X emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. As an alternative, a CO_2 monitor may be used to adjust the measured NO_X concentrations to 15 percent O_2 by either converting the CO_2 hourly averages to equivalent O_2 concentrations using Equation F–14a or F–14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O_2, or by using the CO_2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO_X and diluent monitors may be performed individually or on a combined basis, *i.e.*, the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NO_X) and a percent O_2 basis for oxygen; or

(ii) On a ppm at 15 percent O_2 basis; or

(iii) On a ppm basis (for NO_X) and a percent CO_2 basis (for a CO_2 monitor that uses the procedures in Method 20 to correct the NO_X data to 15 percent O_2).

(2) As specified in § 60.13(e)(2), during each full unit operating hour, each 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 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 to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in § 60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both NO_X and diluent, the data acquisition and handling system must calculate and record the hourly NO_X emissions in the units of the applicable NO_X emission standard under § 60.332(a), *i.e.*, percent NO_X by volume, dry basis, corrected to 15 percent O_2 and International Organization for Standardization (ISO) standard conditions (if required as given in § 60.335(b)(1)). For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(iii) If the owner or operator has installed a NO_X CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in § 60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO_X emissions, the owner or operator may, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA or local permitting authority approval of a petition for an alternative procedure of continuously monitoring compliance with the applicable NO_X emission limit under § 60.332, that approved procedure may continue to be used, even if it deviates from paragraph (a) of this section.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NO_X emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NO_X CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO_X emissions may elect to use a NO_X CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. An acceptable alternative to installing a CEMS is described in paragraph (f) of this section.

(f) The owner or operator of a new turbine who elects not to install a CEMS under paragraph (e) of this section, may instead perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NO_X formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in the lean premixed (low-NO_X) combustion mode.

(3) For any turbine that uses SCR to reduce NO_X emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor 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 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in § 75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under § 60.8, to establish acceptable values and ranges. The owner or operator 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. The owner or operator shall 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 shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in § 75.19 of this chapter or the NO_X emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in § 75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in § 60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86 (all of which are incorporated by reference-see § 60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (*i.e.*, if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in § 60.332). The nitrogen content of the fuel shall be determined using methods described in § 60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in § 60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. 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.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) *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). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) *Gaseous fuel.* Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) *Custom schedules.* Notwithstanding the requirements of paragraph (i)(2) 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 (i)(3)(i) and (i)(3)(ii) 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 § 60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) 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 (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), 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 between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(*1*) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*2*) of this section.

(*2*) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*3*) of this section.

(*3*) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) 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:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (*i.e.*, the maximum total sulfur content of natural gas as defined in § 60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) 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 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with § 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under § 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

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

(A) An excess emission shall be any unit operating hour for which the 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 § 60.332, 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 shall also be considered an excess emission.

(B) A period of monitor downtime shall be 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.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in § 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of § 60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in § 60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) 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 that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NO_X and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_X concentration exceeds the applicable emission limit in § 60.332(a)(1) or (2). For the purposes of this subpart, a ''4-hour rolling average NO_X concentration'' is the arithmetic average of the average NO_X concentration measured by the CEMS for a given hour (corrected to 15 percent O_2 and, if required under § 60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_X concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_X concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in § 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of § 60.335(b)(1).

(iv) For turbines required under paragraph (f) of this section to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(A) An excess emission shall be 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.

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

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) 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 gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall 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 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) 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 shall include only unit operating hours, and ends on the date and hour of the next valid sample.

* * * * *

(5) All reports required under § 60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter.

■ 7. Section 60.335 is revised to read as follows:

§ 60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in § 60.8, using either

(1) EPA Method 20,

(2) ASTM D6522–00 (incorporated by reference, see § 60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NO_X and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall 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.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

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

(A) [Reserved]

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

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

(A) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O_2, is within ±10 percent of the mean normalized concentration for all traverse points, then you may use 3 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 3 points shall be located along the measurement line that exhibited the highest average normalized NO_X concentration during the stratification test; or

(B) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O_2, is within ±5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in § 60.332 and shall meet the performance test requirements of § 60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NO_{Xo}) corrected to 15 percent O_2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$$NO_X=(NO_{Xo})(P_r/P_o)^{0.5}\ e^{19\ (H_o-0.00633)}\ (288°K/T_a)^{1.53}$$

Where:

NO_X = emission concentration of NO_X at 15 percent O_2 and ISO standard ambient conditions, ppm by volume, dry basis,

NO_{Xo} = mean observed NO_X concentration, ppm by volume, dry basis, at 15 percent O_2,

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,

P_o = observed combustor inlet absolute pressure at test, mm Hg,

H_o = observed humidity of ambient air, g H_2O/g air,

e = transcendental constant, 2.718, and

T_a = ambient temperature, °K.

(2) The 3-run performance test required by § 60.8 must be performed within ±5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these

requirements, performance testing is not required for any emergency fuel (as defined in § 60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO_X emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO_X emission limit in § 60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with § 60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522–00 (incorporated by reference, see § 60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable § 60.332 NO_X emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in § 60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in § 60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NO_X CEMS under § 60.334(e), then the initial performance test required under § 60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under § 60.332 and to provide the required reference method data for the RATA of the CEMS described under § 60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator is required under § 60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls, the appropriate parameters shall 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 § 60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597–94 (Reapproved 1999), D6366–99, D4629–02, D5762–02 (all of which are incorporated by reference, *see* § 60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under § 60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129–00, D2622–98, D4294–02, D1266–98, D5453–00 or D1552–01 (all of which are incorporated by reference, *see* § 60.17); or

(ii) For gaseous fuels, ASTM D1072–80, 90 (Reapproved 1994); D3246–81, 92, 96; D4468–85 (Reapproved 2000); or D6667–01 (all of which are incorporated by reference, see § 60.17). 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 prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in § 60.8 to ISO standard day conditions.

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