ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[OAR–2002–0053, FRL–7476–5]

RIN 2060–AK35

Standards of Performance for Stationary Gas Turbines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule; amendments.

SUMMARY: This action promulgates amendments to several sections of the standards of performance for stationary gas turbines. 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 originally promulgated.

DATES: The direct final rule will be effective May 29, 2003, unless we receive adverse comments by May 14, 2003. If such comments are received, then EPA will publish a timely withdrawal in the **Federal Register** indicating which provisions will become effective and which provisions are being withdrawn due to adverse comment. Any distinct amendment, paragraph or section of the direct final rule for which we do not receive adverse comment will become effective on the date set above, notwithstanding any adverse comment on any other distinct amendment, paragraph, or section of the direct final rule. The incorporation by reference of certain publications in the direct final rule is approved by the Director of the Office of the Federal Register as of May 29, 2003.

ADDRESSES: Comments. By U.S. Postal Service, send comments (in duplicate, if possible) to: EPA Docket Center (6102T), Attention Docket Number OAR–2002–0053, U.S. EPA, 1200 Pennsylvania Avenue, NW., Washington, DC 20460. In person or by courier, deliver comments (in duplicate, if possible) to: Air and Radiation Docket, Attention Docket Number OAR–2002–0053, U.S. EPA, 1301 Constitution Avenue, NW., Room B–108, Washington, DC 20460. We request that a separate copy also be sent to the contact person listed below (*see* **FOR FURTHER INFORMATION CONTACT**).

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 direct 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. 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.

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.

Comments. We are publishing the direct final rule without prior proposal because we view this as a noncontroversial amendment and do not anticipate adverse comments. However, in the proposed rules section of this **Federal Register**, we are publishing a separate document that will serve as the proposal in the event that adverse comments are filed. If we receive any adverse comments on a specific element of the direct final rule, we will publish a timely withdrawal in the **Federal Register** informing the public which amendments will become effective and which amendments are being withdrawn due to adverse comment. We will address all public comments in a subsequent final rule based on the proposed rule. Any of the distinct amendments in this direct final rule for which we do not receive adverse comment will become effective on the date set out above. We will not institute a second comment period on the direct final rule. Any parties interested in commenting must do so at this time.

World Wide Web (WWW). In addition to being available in the docket, an electronic copy of the direct final rule is also available on the WWW through the Technology Transfer Network (TTN). Following signature, a copy of the promulgated direct 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.

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 originally promulgated on September 10, 1979 (44 FR 52798). Since that time, many changes in the design of the NO_X emission controls used for and the composition of the fuels fired 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 changes, 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.

II. Discussion of Revisions

A. Continuous Monitoring Options

Under the original provisions of subpart GG, 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 revising 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 May 29, 2003, 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 approval of an alternative monitoring strategy can continue to follow the conditions of the petition approval.

For new turbines constructed after the effective date of the direct final rule 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, operated, and maintained 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 the effective date of the direct final rule 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, operated, and maintained 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 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. Two valid data points 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 data generated using the data substitution methodology in 40 CFR part 75 may be used. Instead, these periods of missing data are identified and summarized in the excess emissions and monitoring report required in 40 CFR 60.13. 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 averaging time selected for combustion turbine NO_X CEMS to define the periods of excess emissions is a period of 4 hours averaged each hour. The 4-hour period is representative of the overall elapsed time in a typical EPA Method 20 of 40 CFR part 60, appendix A, source test. This period has been found adequate to represent the performance of combustion turbine NO_X emissions and NO_X emission control systems. The 4-hour period is a relatively short averaging time compared to 24-hour and monthly averaging times used for other types of combustion devices to account for the NO_X emissions variability, particularly in solid fuels. Combustion turbines typically use natural gas or No. 2 distillate oil, which have a relatively uniform fuel nitrogen content, therefore, a relatively short averaging time such as 4 hours is appropriate. An averaging time of 1 hour was also considered but was rejected since 4 hours more closely represent the typical duration of a combustion turbine stack test and includes the ability to account for a small amount of nitrogen variability.

A 1-hour period was selected as the recurring (rolling) period for which the 4-hour averages are calculated since it is already required to be reported under 40 CFR part 75 and is convenient and appropriate to use.

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 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. We, therefore, believe 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, deviations, 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 promulgation of the direct final rule. 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. 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.

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

We are amending subpart GG 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, the sampling requirements to determine the daily fuel nitrogen concentrations are not required.

2. Nitrogen and Sulfur Content for Turbines Firing Fuel Oil

The sampling frequency for determining the nitrogen and sulfur content of fuel oil has been revised. 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.

3. 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. We believe that sulfur sampling is unnecessary for fuels that qualify as natural gas. As defined in the direct final rule, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet, which equates to about 0.06 weight percent sulfur or 600 parts per million by weight (ppmw). When natural gas is combusted, there is no possibility of exceeding the subpart GG sulfur limit of 0.8 weight percent.

4. 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 direct final rule, or they may develop a custom schedule that is approved by the 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 annually. 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 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 was originally 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. As the National Technology Transfer and Advancement Act requires, 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. If ASTM D6522–00 or EPA Methods 7E and 3 or 3A are used, sampling must be conducted at a minimum of three traverse points, due to concerns about potential stratification of pollutant concentrations in the turbine stack.

Subpart GG 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 revising the final rule to allow one test point at 90 to 100 percent of peak load. 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 at 90 to 100 percent of peak load only, 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. We believe that 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 heat recovery steam generators 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.

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. Deviations, Excess Emissions, and Monitor Downtime

The excess emission reporting provisions under 40 CFR 60.334 have been revised to include definitions of deviations, excess emissions, and monitor downtime periods for the various emissions and parameter monitoring requirements. To be consistent with other 40 CFR part 60 rules, we are including provisions for deviations, which are associated with parametric monitoring. A deviation indicates the possibility that an excess emission has occurred. 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, deviations, 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. Environmental and Economic Impacts

We believe that the amendments will not have any significant economic or environmental impacts. The changes have been made 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.

IV. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

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

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

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

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

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

Pursuant to the terms of Executive Order 12866, we have determined that the amendments do not constitute a ''significant regulatory action'' because they do not meet any of the above criteria. Consequently, this action was not submitted to OMB for review under Executive Order 12866.

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 revisions contain no changes to the information collection requirements of the current New Source Performance Standards (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 changes 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 changes, 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 Act

The Regulatory Flexibility Act (RFA), as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 *et seq.*, generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of the direct 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 direct 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 direct final rule on small entities, we certify that this action will not have a significant economic impact on a substantial number of small entities. This certification 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 combustion turbines currently is a good approximation of the mix of turbines that will be installed and affected by the direct 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 direct 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 direct final rule amendments are not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled ''Federalism'' (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 direct 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 direct final rule amendments.

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

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (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 direct 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 direct 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 direct 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 direct 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 direct final rule is not subject to Executive Order 13211, ''Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use'' 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 (Public Law No. 104–113; 15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

The direct final rule involves technical standards. The EPA cites the following standards in the direct final rule: EPA Methods 3, 3A, 7E, and 20 of 40 CFR part 60, appendix A; PS 2 and 3 of 40 CFR part 60, appendix B.

In addition, the direct final rule cites the following voluntary consensus standards: ASTM D129–00 (incorporated by reference (IBR) in 40 CFR part 60, section 17), ASTM D1072–80 or –90 (Reapproved 1999) (IBR in 40 CFR part 60, section 17), ASTM D1266–98 (IBR in 40 CFR part 60, section 17), ASTM D1552–01 (IBR in 40 CFR part 60, section 17), ASTM D2597–94 (Reapproved 1999), ASTM D2622–98 (IBR in 40 CFR part 60, section 17), ASTM D3246–81 or –92 or –96 (IBR in 40 CFR part 60, section 17), ASTM D4084–82 or –94 (IBR in 40 CFR part 60, section 17), 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 the EPA methods. No applicable voluntary consensus standards were identified for EPA PS 3. The search and review results have been documented and are placed in the docket (OAR–2002–0053) for the direct final rule.

One voluntary consensus standard was found acceptable as an alternative to EPA test methods for the purposes of the direct final rule. The voluntary consensus 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' was identified as an acceptable alternative to EPA Methods 3A, 7E, and 20 for identifying nitrogen oxide and oxygen concentration for the direct final rule when the fuel is natural gas.

In addition to the voluntary consensus standards EPA uses in the direct final rule, the search for emissions measurement procedures identified six other voluntary consensus standards. The EPA determined that these six standards identified for measuring emissions subject to emission standards were impractical alternatives to EPA test methods for the purposes of the direct final rule. Therefore, EPA does not intend to adopt these standards for this purpose. The reasons for this determination for the six methods are in the docket.

Section 60.335 to 40 CFR part 60, subpart GG, lists the EPA testing methods included in the final rule. Under 40 CFR 63.7(f) and 63.8(f), 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 direct 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 direct final rule in the **Federal Register**. The direct 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: March 27, 2003.

Christine Todd Whitman,

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, P.O. 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).

(2) [Reserved]

* * * * *

Subpart GG—[AMENDED]

■ 3. Section 60.331 is amended by adding paragraphs (s) through (aa) 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) *Deviation* means a unit operating hour during which the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

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

(v) *Natural gas* means a naturally occurring fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 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.

(w) *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.

(x) *Lean premix stationary combustion turbine* means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor.

(y) *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.

(z) *Unit operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

■ 4. Section 60.332 is amended by:

■ a. Revising the terms to the equations in paragraphs (a)(1) through (3);

■ b. Redesignating paragraph (a)(3) as (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 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 § 60.332(a)(1) and (2) 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 § 60.332(a)(4) 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 paragraphs (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, certify 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 May 29, 2003, 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. If this option is chosen, the CEMS shall be installed, certified, maintained, operated and quality-assured 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 or in accordance with the requirements of appendix A to part 75 of this chapter. The relative accuracy test audit (RATA) of the NO_X and O_2 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.

(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 O_2, 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)).

(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 (H_o), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(iii) The missing data substitution methodology provided for at 40 CFR Part 75, subpart D may not be used 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).

(4) Data from the CEMS shall be quality-assured, either in accordance with § 60.13, or in accordance with appendix B to part 75 of this chapter (or, if applicable, § 75.74(c)(2) and (3) of this chapter).

(c) For any new turbine that commenced construction, reconstruction or modification after October 3, 1977, but before May 29, 2003, 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 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 May 29, 2003, 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 May 29, 2003, 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. The parameters described in § 75.19(c)(1)(iv)(H)(2) of this chapter are acceptable for this purpose.

(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.

(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 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).

(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(v), 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 new turbine that commenced construction, reconstruction or modification after October 3, 1977, but before May 29, 2003, 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 subparagraphs (A) through (D) of this paragraph, (i)(3)(i), 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(v)), 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 (or deviations, as applicable) and monitor downtime, in accordance with § 60.7(c). For the purpose of reports required under § 60.7(c), periods of excess emissions (or deviations) 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) A deviation 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 a deviation.

(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 deviation.

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

(A) A deviation 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 deviation 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 O_2 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 quality-assured 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 quality-assured 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 percent O_2 (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.

(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) A deviation 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 period shall begin 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. The excess emission period ends 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 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 amended by:

■ a. Removing paragraphs (a), (d) and (e);

■ b. Redesignating paragraphs (b) and (c) as paragraphs (a) and (b), respectively;

■ c. Revising the new paragraphs (a) and (b);

■ d. Redesignating paragraph (f) as paragraph (c); and

■ e. Revising the new paragraph (c)(1).

The revisions and additions 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 EPA Method 20, ASTM D6522–00 (incorporated by reference, *see* § 60.17), or EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NO_X and diluent concentration, except as provided in § 60.8(b). If ASTM D6522–00 (incorporated by reference, *see* § 60.17) or EPA Methods 7E and 3A (or 3) are used, the owner or operator shall perform a stratification test for NO_X and diluent pursuant to the procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter. Once the stratification sampling is completed, the owner or operator shall analyze the data using the procedures in section 6.5.6.3(a) and (c) to determine if subsequent RATA testing will occur along a short (0.4, 1.2 and 2.0 meters from the stack or duct wall) or long (16.7, 50.0, and 83.3 percent of the way across the stack or duct) reference measurement line. The short or long reference method measurement line, as determined above, will serve in lieu of the sampling points usually required by EPA Method 20. In no case shall the RATA be based on fewer than three sample points as specified in section 8.1.3.2 of PS 2 in appendix B to this part. 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 nitrogen oxides emission concentration (NO_{XO}) obtained using EPA Method 20, ASTM D6522–00 (incorporated by reference, see § 60.17), or EPA Method 7E shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the 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} = observed NO_X concentration, ppm by volume, dry basis, at 15 percent O_2, corrected using either EPA Method 20 or Method 3 or 3A data,

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. 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 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) * * *

(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.

(2) [Reserved]

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