MEMORANDUM

To: Docket EPA-HQ-OAR-2024-0419

From: U.S. EPA

Subject: New subpart KKKKa Proposed Rule Text

The attachments to this memorandum, for the convenience of interested parties, present subpart KKKKa as proposed in Review of New Source Performance Standards for Stationary Combustion Turbines and Stationary Gas Turbines.

Subpart KKKKa—Standards of Performance for Stationary Combustion Turbines

Introduction

§60.4300a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification, or reconstruction after **[INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER].**

Applicability

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

(a) Except as provided for in §60.4310a, you are subject to this subpart if you own or operate a stationary combustion turbine that commenced construction, modification, or reconstruction after **[INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER]** and that has a base load rating equal to or greater than 10.7 gigajoules per hour (GJ/h) (10 million British thermal units per hour (MMBtu/h)). Any additional heat input from duct burners used with heat recovery steam generating (HRSG) units or fuel preheaters is not included in the heat input value used to determine the applicability of this subpart to a given stationary combustion turbine. However, this subpart does apply to emissions from any associated HRSG, duct burner(s), and fuel preheater(s) that are associated with a combustion turbine subject to this subpart.

(b) For the purpose of this subpart, only the simple cycle portion of a combined cycle and/or combined heat and power (CHP) stationary combustion turbine is used to determine whether the affected facility is new or reconstructed. When determining if a facility is new or reconstructed, do not include the equipment associated with the HRSG, as included in the definition of a stationary combustion turbine.

Commented [A1]: Adding a HRSG with duct burners to an existing turbine could still trigger modification

(c) A stationary combustion turbine subject to this subpart is not subject to subpart GG or subpart KKKK of this part.

(d) Duct burners are not subject to subparts D, Da, Db, or Dc of this part (as applicable) if the duct burner is used with a HRSG unit that is part of a combustion turbine that is subject to this subpart.

Commented [A2]: HRSG burning a solid fuel would also have to comply with one of the steam generating units NSPS (D, Da, Db, or Dc).

(e) If you own or operate either a stationary combustion turbine (including a combined cycle combustion turbine or a CHP combustion turbine) that commenced construction, modification, or reconstruction on or before **[INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, you may submit a written petition to the Administrator requesting that the stationary combustion turbine comply with the applicable requirements for modified units under this subpart as an alternative to complying with subparts GG or KKKK of this part, and with subparts D, Da, Db, and Dc of this part, as applicable. If the Administrator or delegated authority approves the petitioner's request, the affected facility must comply with the requirements for modified units under this subpart unless the stationary combustion turbine is reconstructed or replaced with a new facility in the future.

§60.4310a What stationary combustion turbines are not subject to this subpart?

(a) An integrated gasification combined cycle electric utility steam generating unit subject to subpart Da of this part is not subject to this subpart.

(b) A stationary combustion turbine used in a combustion turbine test cell/stand, as defined in §60.4420a, is not subject to this subpart.

(c) If any solid fuel is combusted in the HRSG, the HRSG is not subject to this subpart.

Commented [A3]: Soliciting comment on and not proposing

(f) Owners and operators of combustion turbines that is subject to this subpart are exempt from the title V permitting requirements obligation under 40 CFR part 70 and 40 CFR part 71 if you meet the criteria in paragraphs (f)(1) and (2) of this section:.
(1) You are an owner or operator of a non-major source that is subject to this subpart; and
(2) You are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as a non-major source under this subpart.

If exempted in the final rule add the following 60.4310a:
•Temporary combustion turbines

Emission Standards

§60.4315a What pollutants are regulated by this subpart?

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

§60.4320a What NO_X emissions standard must I meet?

(a) Except as provided for in paragraph (c) of this section, for each stationary combustion turbine you must not discharge into the atmosphere from the affected facility any gases that contain an amount of NO_X that exceeds the applicable emissions standard and be in accordance with the requirements specified in paragraph (b) of this section. Input-based emission rates and standards are determined on a 4-operating hour basis and output-based emission rates and standards are determined on a 30-operating day basis.

(b) For the purpose of determining compliance with the applicable emissions standard, you must also meet the requirements specified in paragraphs (b)(1) through (b)(4) of this section, as applicable to your affected facility.

(1) The NO_X emission standard that is applicable to your affected facility shall be determined on an operating hour basis, unless you elect to use the alternative provided for in paragraph (b)(2) of this section. Determining the hourly NO_X emission standards for your affected facility requires recording hourly data and maintaining records according to the requirements in §60.4390a.

(2) As an alternative to the requirements specified in paragraph (c)(1) of this section, you may elect to use the lowest NO_X emission standard that is applicable to your affected facility, as determined using table 1 to this subpart, for the entire required compliance period.

(3) During each operating hour when the total heat input (based on the HHV of the fuels) of the combustion turbine engine is greater than or equal to 50 percent natural gas, as defined in §60.4420a, you must meet the NO_X emission standard as determined by the applicable size category in table 1 to this subpart which corresponds to a stationary combustion turbine firing natural gas. During each operating hour when the total heat input to the combustion turbine engine is less than 50 percent you must meet the NO_X emission standard as determined by the applicable size category in table 1 to this subpart which corresponds to a stationary combustion turbine firing fuels other than natural gas.

(4) If you have two or more combustion turbine engines connected to a single electric generator, each of the combustion turbine engines must individually meet their respective, applicable NO_X emission standard as determined using table 1 to this subpart.

(c) Stationary combustion turbines that meet at least one of the specifications described in paragraphs (c)(1) through (3) of this section are exempt from the applicable NO_X emission standard in paragraphs (a) and (b) of this section.

(1) An emergency combustion turbine, as defined in §60.4420a,

(2) A stationary combustion turbine that, as determined by the Administrator or delegated authority, is used for the research and development of control techniques and/or efficiency improvements relevant to stationary combustion turbine emissions, or

(3) A stationary combustion turbine that combusts by-product fuels for which a facility-specific NO_X emission standard has been established by the Administrator according to the requirements of paragraphs (d)(3)(i) and (ii) of this section.

(i) You may request a facility-specific NO_X emission standard by submitting a written request to the Administrator or delegated authority explaining why your affected facility, when combusting the by-product fuel, is unable to comply with the applicable NO_X emission standard determined using table 1 to this subpart.

(ii) If the Administrator approves the request, a letter will be sent to the facility describing the facility-specific NO_X emission standard. You must use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(d) You must meet the applicable NO_X emissions standard to your affected facility during all times that the affected facility is operating (including periods of startup, shutdown, and malfunction).

§60.4330a What SO_2 emissions standard must I meet?

(a) Except as provided for in paragraphs (b) through (f) of this section, for each stationary combustion turbine you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO_2 exceeding either:

(1) 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross energy output; or

(2) 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

(b) For each stationary combustion turbine combusting 50 percent or more low-Btu gas per calendar month based on total heat input (using the higher heating value of the fuel), you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO_2 exceeding either:

(1) 650 milligrams of sulfur per standard cubic meter (mg/scm) (28 grains (gr) of sulfur per 100 standard cubic

Commented [A4]: Pending public comment this could be amended to apply the natural gas based standard during periods when only natural gas is combusted.

(3) During each operating hour when only natural gas, as defined in §60.4420a, is combusted in the combustion turbine engine, you must meet the NO_X emission standard as determined by the applicable size category in table 1 to this subpart which corresponds to a stationary combustion turbine firing natural gas. During each operating hour when any fuel other than natural gas is combusted in the combustion turbine engine, you must meet the NO_X emission standard as determined by the applicable size category in table 1 to this subpart which corresponds to a stationary combustion turbine firing fuels other than natural gas. If multiple fuels are combusted during a given operating hour, then the highest applicable NO_X emissions standard is applied for the entire operating hour.

Commented [A5]: Pending public comment, the exemption for military and firefighting combustion turbines could be added in paragraph (c).

Commented [A6]: Flexibility to petition for facility-specific NOx standard – similar to subpart Db.

Commented [A7]: Soliciting comment on exempting combustion turbines with permit restrictions to low sulfur fuels from the SO2 standard

Commented [A8]: Alternate SO2 standard for combustion turbines combusting fuel(s) comprising a majority of low-Btu gases feet (scf)); or

(2) 65 ng SO_2/J (0.15 lb SO_2/MMBtu) heat input.

(c) For each stationary combustion turbine located in a noncontinental area, you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO_2 exceeding either:

(1) 780 ng/J (6.2 lb/MWh) gross energy output; or

(2) 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input.

(d) For each stationary combustion turbine for which the Administrator determines that the affected facility does not have access to natural gas and that the removal of sulfur compounds from the fuel would cause more environmental harm than benefit, you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO_2 exceeding either:

(1) 780 ng/J (6.2 lb/MWh) gross energy output; or

(2) 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input.

(e) A stationary combustion turbine subject to either subpart J or Ja of this part is not subject to the SO_2 performance standards in this subpart.

(f) A stationary combustion turbine is not subject to any SO_2 emission standard in this subpart if the stationary combustion turbine is subject to a federally enforceable requirement that:

(1) limits the sulfur content of gaseous fuels combusted in the stationary combustion turbine to no more than 460 mg/scm (20 gr/100 scf); and/or

(2) limits the sulfur content of liquid fuels to no more than 0.015 weight percent sulfur (15 ppmw).

General Compliance Requirements

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

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

(b) If you own or operate a stationary combustion turbine subject to a NO_X emissions standard in §60.4320a, you must conduct an initial performance test according to §60.8 using the applicable methods in §60.4400a or §60.4405a. Thereafter, unless you perform continuous monitoring consistent with §60.4335a, §60.4340a, or §60.4345a, you must conduct subsequent performance tests according to the applicable requirements in paragraphs (b)(1) through (b)(6) of this section.

(1) Except as provided for in paragraphs (b)(2) through (b)(5) of this section, you must conduct subsequent performance tests within 12 calendar months of the date that the previous performance test was conducted.

(2) If the NO_X emission result from the most recent performance test is less than or equal to 75 percent of the NO_X emissions standard for the stationary combustion turbine, you may reduce the frequency of subsequent performance tests to 24 calendar months following the date the previous performance test was conducted. If the results of any subsequent performance test exceed 75 percent of the NO_X emissions standard for the stationary combustion turbine, you must resume 12-calendar month performance testing.

(3) An affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 45 calendar days after the next operating day. The Administrator or delegated authority must be notified of recommencement of operation consistent with §60.4375a(d).

(4) If you own or operate an affected facility that has operated 50 operating hours or less, either in total or using a particular fuel, since the date on which the previous performance test was conducted, you may request that the otherwise required performance test be postponed until the affected facility has operated more than 50 operating hours, either in total or using a particular fuel, since the date on which the previous performance test was conducted. A request for an extension under this paragraph must be addressed to the relevant air division or office director of the appropriate Regional Office of the U.S. EPA as identified in §60.4(a) for his or her approval at least 30 calendar days prior to the date on which the performance test is required to be conducted. If a postponement is approved, a performance test must be conducted within 45 calendar days after the day that the facility reaches 50 hours of operation since the date on which the previous performance test was conducted. When

Commented [A9]: Concentration based alternative approximately equivalent to 500 ppm S by volume

Commented [A10]: Facilities with water/steam injection, parametric monitoring, or CEMS not required to perform an annual test.

Commented [A11]: Add automatic extension of performance test requirement for owner/operators of turbines that are not operating.

Commented [A12]: Add ability of low capacity factor turbines to request an extension on the date of the required performance test. Fuel specific so can request extension on rarely fired backup fuels as well.

the facility has operated more than 50 operating hours since the date on which the previous performance test was conducted, the Administrator or delegated authority must be notified consistent with §60.4375a(e).

(5) For a facility at which a group consisting of no more than five similar stationary combustion turbines (i.e., same manufacturer and model number) is operated, you may request the use of a custom testing schedule by submitting a written request to the Administrator or delegated authority. The minimum requirements of the custom schedule include the conditions specified in paragraphs (5)(i) through (v) of this section.

Commented [A13]: Multiple similar units only have to test once every 5 years. Since less that 75% of applicable standard is required 60.4333a(b)(2) automatically applies

(i) Emissions from the most recent performance test for each individual affected facility are 75 percent or less of the applicable standard;

(ii) Each stationary combustion turbine uses the same emissions control technology;

(iii) Each stationary combustion turbine is operated in a similar manner;

(iv) Each stationary combustion turbine and its emissions control equipment are maintained according to the manufacturer's recommended maintenance procedures; and

(v) A performance test is conducted on each affected facility at least once every 5 calendar years.

(6) A stationary combustion turbine subject to a NO_X emissions standard in §60.4320a that exchanges the combustion turbine engine for an overhauled combustion turbine engine as part of an exchange program, must conduct an initial performance test according to §60.8 using the applicable methods in §60.4400a or §60.4405a. (as applicable).

(c) Except as provided for in paragraphs (c)(1) or (2) of this section, for each stationary combustion turbine subject to a NO_X emissions standard in §60.4320a, you must demonstrate continuous compliance using a continuous emissions monitoring system (CEMS) for measuring NO_X emissions according to the provisions in §60.4345a. If your stationary combustion turbine is equipped with a NO_X CEMS, those measurements must be used to determine excess emissions.

(1) If your stationary combustion turbine uses water or steam injection but not post-combustion controls to meet the applicable NO_X emissions standard in §60.4320a, you may elect to demonstrate continuous compliance using the pounds per million British thermal units (lb/MMBtu) standard according to the provisions in §60.4335a.

(2) If your stationary combustion turbine does not use water injection, steam injection, or post-combustion controls to meet the applicable NO_X emissions standard in §60.4320a, you may elect to demonstrate continuous compliance with the lb/MMBtu standard according to the provisions in §60.4340a.

(d) An owner or operator of a stationary combustion turbine subject to an SO_2 emissions standard in §60.4330a must demonstrate compliance using one of the methods specified in paragraphs (d)(1) through (4) of this section.

(1) Conduct an initial performance test according to §60.8 and use the applicable methods in §60.4415a. Thereafter, you must conduct subsequent performance tests within 12 calendar months following the date the previous performance test was conducted. An affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 45 calendar days after the next operating day;

(2) Conduct an initial performance test according to §60.8 and use the applicable methods in §60.4415a. Thereafter, conduct subsequent fuel sulfur analyses using the applicable methods specified in §60.4360a and at the frequency specified in §60.4370a;

(3) Conduct an initial performance test according to §60.8 and use the applicable methods in §60.4415a. Thereafter, maintain records (such as a current, valid purchase contract, tariff sheet, or transportation contract) documenting that total sulfur content for the initial and subsequent fuel combusted in your stationary combustion turbine at all times does not exceed applicable conditions specified in §60.4370a; or

(4) Conduct an initial performance test according to §60.8 using the applicable methods in §60.4415a. Thereafter, continue to monitor SO_2 emissions using a CEMS according to the requirements specified in §60.4374a.

(e) If you elect to comply with an input-based standard (lb/MMBtu) and your affected facility includes use of one or more heat recovery steam generating units, then you must determine compliance with the applicable NO_X and SO_2 emission standards according to the procedures specified in paragraphs (e)(1) or (2) of this section as applicable to the heat recovery steam generating unit configuration used for your affected facility.

Commented [A14]: Procedures to address more complicated (interconnected) configurations.

(1) For a configuration where a single combustion turbine engine is exhausted through the heat recovery steam generating unit, you must measure both the emissions at the exhaust stack for the heat recovery steam generating

unit and the fuel flow to the combustion turbine engine and any associated duct burners.

(2) For a configuration where two or more combustion turbine engines are exhausted through a single heat recovery steam generating unit, you must measure both the total emissions at the exhaust stack for the heat recovery steam generating unit and the total fuel flow to each combustion turbine engine and any associated duct burners. The applicable emissions standard for the affected facility is equal to the most stringent emissions standard for any individual combustion turbine engine.

(f) If you elect to comply with an output-based standard (lb/MWh) and your affected facility includes use of one or more heat recovery steam generating units, then you must determine compliance with the applicable NO_X and SO_2 emission standards according to the procedures in paragraphs (f)(1), (2), or (3) of this section as applicable to the heat recovery steam generating unit configuration used for your affected facility.

(1) For a configuration where a single combustion turbine engine is exhausted through the heat recovery steam generating unit, you must measure both the emissions at the exhaust stack for the heat recovery steam generating unit and the total electrical, mechanical energy, and useful thermal output of the stationary combustion turbine (as applicable).

(2) For a configuration where two or more combustion turbine engines are exhausted through a single heat recovery steam generating unit, you must measure both the total emissions at the exhaust stack for the heat recovery steam generating unit, and the total electrical, mechanical energy, and useful thermal output of the heat recovery steam generating unit and each combustion turbine engine (as applicable). The applicable emissions standard for the affected facility is equal to the most stringent emissions standard for any individual combustion turbine engines.

(3) For a configuration where your combustion turbine engines are exhausted through two or more heat recovery steam generating units which serve a common steam turbine or steam header, you must measure both the emissions at the exhaust stack for each heat recovery steam generating unit and the total electrical or mechanical energy output of each combustion turbine engine (as applicable). To determine the net or gross energy output of the steam produced by the heat recovery steam generating unit, you must develop a custom method and provide information, satisfactory to the Administrator or delegated authority, apportioning the net or gross energy output of the steam produced by the heat recovery steam generating units to each of the affected stationary combustion turbines.

Monitoring

§60.4335a How do I demonstrate compliance with my NO_X emissions standard without using a NO_X CEMS if I use water or steam injection?

If you qualify and elect to demonstrate continuous compliance according to the provisions of §60.4333a(c)(1), you must install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the fuel consumption and the water or steam to fuel ratio fired in the combustion turbine engine consistent with the requirements in §60.4342a. Water or steam only needs to be injected when a fuel is being combusted that requires water or steam injection for compliance with the applicable NO_X emissions standard.

§60.4340a How do I demonstrate compliance with my NO_X emissions standard without using a NO_X CEMS if I do not use water or steam injection?

(a) If you qualify and elect to demonstrate continuous compliance according to the provisions of §60.4333a(c)(2), you must demonstrate compliance with the NO_X emissions standard using one of the methods specified in paragraphs (a)(1) through (3) of this section.

(1) Conduct performance tests according to requirements in §60.4400a;

(2) Monitor the NO_X emissions rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in 40 CFR 75.19; or

(3) Install, calibrate, maintain, and operate an operating parameter continuous monitoring system according to the requirements specified in paragraph (b) of this section and consistent with the requirements specified in §60.4342a.

(b) Continuous operating parameter monitoring must be performed using the methods specified in paragraphs (b)(1) through (4) of this section as applicable to the stationary combustion turbine.

Commented [A15]: Essentially treat the configuration as a single affected facility except new and reconstruction is based on each individual turbine engine and the applicable standard is the most stringent standard for each turbine.

Commented [A16]: Essentially treat the configuration as a single affected facility except new and reconstruction is based on each individual turbine engine and the applicable standard is the most stringent standard for each turbine.

Commented [A17]: If the combustion turbine engines are identical, the default is to apportion the output based on the heat input to the individual combustion turbine engines

Commented [A18]: NOx estimation protocol for gas-fired peaking and oil-fired peaking. Allow without approval.

Commented [A19]: Optional SO2, NOx, and CO2 emission calculation for low mass emissions (LME) units.
Low mass emissions excepted methodology, calculations, and values. Allow without approval.

(1) Selection of the operating parameters used to comply with this paragraph must be identified in the performance test report. The selection of operating parameters is subject to the review and approval of the Administrator or delegated authority.

(2) For a lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode during periods when low-NO_X operation is required to comply with the applicable emission NO_X standard.

(3) For a stationary combustion turbine other than a lean premix stationary combustion turbine, you must define parameters indicative of the unit's NO_X formation characteristics and monitor these parameters continuously.

(4) You must perform the parametric monitoring described in section 2.3 in appendix E to part 75 of this chapter or in 40 CFR 75.19(c)(1)(iv)(H).

§60.4342a How do I monitor NO_X control operating parameters?

(a) If you monitor steam or water to fuel ratio according to §60.4335a or other parameters according to §60.4340a, the applicable parameters must be continuously monitored and recorded during the performance test, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations, and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan must include the information specified in paragraphs (a)(1) through (6) of this section:

(1) Identification of the parameters to be monitored and show there is a significant relationship to emissions and proper operation of the NO_X emission controls;

(2) Selected parameter ranges (or designated conditions) indicative of proper operation of the stationary combustion turbine NO_X emission controls, or describe the process by which such range (or designated condition) will be established;

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

(4) Description of quality assurance and control practices used to ensure the continuing validity of the data;

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

(6) Justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges.

(b) The water or steam to fuel ratio and parameter continuous monitoring system ranges must be reestablished at least once every 60 calendar months following the previous calibration and each time the combustion turbine engine is replaced with an overhauled turbine engine as part of an exchange program. An affected facility that has not operated for 60 calendar days prior to the due date of a recalibration you are not required to perform the subsequent recalibration until 45 calendar days after the next operating day.

Commented [A20]: 60 month performance test to assure the control is still working properly.

Commented [A21]: Grace period so facilities do not have to startup just to verify calibration.

§60.4345a How do I demonstrate compliance with my NO_X emissions standard using a NO_X CEMS?

(a) Each CEMS measuring NO_X emissions used to meet the requirements of this subpart, must meet the requirements in paragraphs (a)(1) through (6) of this section.

(1) You must install, certify, maintain, and operate a NO_X monitor to determine the hourly average NO_X emissions in the units of the standard with which you are complying;

(2) If you elect to comply with an input-based emissions standard, you must install, calibrate, maintain, and operate either a fuel flow meter (or flow meters) or an O_2 or CO_2 CEMS and a stack flow meter to continuously measure the heat input to the affected facility;

(3) If you elect to comply with an output-based emissions standard, you must also install, calibrate, maintain, and operate both a watt meter (or meters) to continuously measure the gross electrical output from the affected facility

and a stack flow meter. If you have a CHP combustion turbine and elect to comply with an output-based emissions standard, you must also install, calibrate, maintain, and operate meters to continuously determine the total useful recovered thermal energy. For steam this includes flow rate, temperature, and pressure. If you have a direct mechanical drive application and elect to comply with the output-based emissions standard you must submit a plan to the Administrator or delegated authority for approval of how energy output will be determined.

Commented [A22]: Mechanical output not as straight forward to measure as electrical output in all situations.

(4) If you elect to comply with the part load NO_X emissions standard, you must install, calibrate, maintain, and operate either a fuel flow meter (or flow meters) or an O_2 or CO_2 CEMS and a stack flow meter to continuously measure the heat input to the affected facility.

(5) If you elect to comply with the temperature dependent NO_X emissions standard, you must install, calibrate, maintain, and operate a thermometer to continuously monitor the ambient temperature.

(6) If you combust natural gas with fuels other than natural gas and elect to comply with the fuels other than natural gas NO_X emissions standard, you must install, calibrate, maintain, and operate a device to continuously monitor when a fuel other than natural gas fuel is combusted in the combustion turbine engine.

(b) Each NO_X CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part. The span value must be 125 percent of the highest applicable standard or highest anticipated hourly NO_X emissions rate. For stationary combustion turbines that do not use post-combustion technology to reduce emissions of NO_X to comply with the requirements of this subpart, the Administrator or delegated authority may approve the use of the NO_X and diluent CEMS that are installed and certified according to appendix A of part 75 of this chapter in lieu of Procedure 1 in appendix F to this part and the requirements of §60.13 of this part, except that the relative accuracy test audit (RATA) of the CEMS must be performed on a lb/MMBtu basis.

(c) During each full operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour. For partial operating hours, at least one data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two data points (one in each of two quadrants) are required for each monitor.

(d) Each fuel flow meter must be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, fuel flow meters that meet the installation, certification, and quality assurance requirements in appendix D to part 75 of this chapter are acceptable for use under this subpart.

Commented [A23]: Optional SO2 emissions data protocol for gas-fired and oil-fired units. Allow without approval.

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

(f) You must develop, submit to the Administrator or delegated authority for approval, maintain, and adhere to an on-site quality assurance (QA) plan for all of the continuous monitoring equipment you use to comply with this subpart. At a minimum, such a QA plan must address the requirements of §§60.13(d), (e), and (h) of this part. For the CEMS and fuel flow meters, the owner or operator of a stationary combustion turbine that does not use post-combustion technology to reduce emissions of NO_X to comply with the requirements of this subpart may, with approval of the Administrator or delegated authority, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 in appendix B to part 75 of this chapter in lieu of the requirements in §60.13(d)(1).

(g) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-operating day rolling average basis.

Commented [A24]: Minimum data availability requirement

§60.4350a How do I use the NO_X CEMS data to determine excess emissions?

(a) If you demonstrate continuous compliance using a CEMS for measuring NO_X emissions, excess emissions are defined as the applicable compliance period for the stationary combustion turbine (either 4-operating hours or 30-operating days), during which the average NO_X emissions from your affected facility measured by the CEMS is greater than the applicable maximum allowable NO_X emissions standard specified in §60.4320a as determined using the procedures specified in this section that apply to your stationary combustion turbine.

(b) The NO_X CEMS data for each operating hour as measured according to the requirements in §60.4345a must be used to determine the hourly average NO_X emissions. The hourly average for a given operating hour is the average of all data points for the operating hour. However, for any periods during which the NO_X, diluent, flow, watt, steam pressure, or steam temperature monitors (as applicable) are out-of-control, the data points are not used in determining the hourly average NO_X emissions. All data points that are not collected during out-of-control periods must be used to determine the hourly average NO_X emissions.

(c) For each operating hour in which an hourly average is obtained, the data acquisition and handling system must calculate and record the hourly average NO_X emissions in units of lb/MMBtu, using the appropriate equation from EPA Method 19 in appendix A-7 of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(d) Data used to meet the requirements of this subpart shall not include substitute data values derived from the missing data procedures of part 75 of this chapter, nor shall the data be bias adjusted according to the procedures of part 75 of this chapter.

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages. However, for any periods during which the flow, watt, steam pressure, or steam temperature monitors (as applicable) are out-of-control, the data points are not used in determining the appropriate hourly average value.

(f) Calculate the hourly average NO_X emissions rate, in units of the emissions standard under §60.4320a, using lb/MMBtu for units complying with the input-based standard or equation 1 to this subpart for units complying with the output-based standard:

(1) For a stationary combustion turbine complying with an output-based emission standard use equation 1.

$$E = \frac{(NO_x)_h \times Q}{P} \quad \text{(Eq. 1)}$$

Where:

E = Hourly NO_X emissions rate, in lb/MWh,

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

Q = Hourly heat input to the stationary combustion turbine, in MMBtu, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D–15a in appendix D to part 75 of this chapter, an O_2 or CO_2 CEMS and a stack flow meter, or the methodologies in appendix F to part 75 of this chapter, and

P = Gross or Net energy output of the stationary combustion turbine in MWh.

(2) The gross or net energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine engine; the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generating unit; the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MWh, minus the auxiliary load as calculated using equations 2 and 3 to this subpart;:

$$P = \frac{(Pe)_t}{T} + \frac{(Pe)_c}{T} - Pe_A + P_s + P_o \quad \text{(Eq. 2)}$$

Where:

P = Gross or net energy output of the stationary combustion turbine system in MWh,

$(Pe)_t$ = Electrical or mechanical energy output of the combustion turbine engine in MWh,

$(Pe)_c$ = Electrical or mechanical energy output (if any) of the steam turbine in MWh,

Pe_A = Electric energy used for any auxiliary loads in MWh (only applicable to owners/operators electing to demonstrate compliance on a net output basis),

P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh, and

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

T = Electric Transmission and Distribution Factor. Equal to 0.95 for CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of electric or direct

Commented [A25]: Subject to comment solicitation mechanical output and 20.0 percent of the total gross useful energy output consists of useful thermal output on an annual basis. Equal to 1.0 for all other combustion turbines.

$$P_s = \frac{Q_m \times H}{3.413 \times 10^6 \; Btu/MWh} \quad \text{(Eq. 3)}$$

Where:

P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh,
Q_m = Measured steam flow in lb,
H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and
3.413×10^6 = Conversion factor from Btu to MWh.

(3) For mechanical drive applications complying with the output-based standard, use equation 4 to this subpart:

$$E = \frac{(NO_x)_m}{BL \times AL} \quad \text{(Eq. 4)}$$

Where:

E = NO_X emissions rate in lb/MWh,
$(NO_x)_m$ = NO_X emissions rate in lb/h,
BL = Manufacturer's base load rating of turbine, in MW, and
AL = Actual load as a percentage of the base load rating.

(g) For each stationary combustion turbine demonstrating compliance on a heat input-based emissions standard, excess NO_X emissions are determined on a 4-operating hour averaging period basis using the NO_X CEMS data and procedures specified in paragraphs (g)(1) and (2) of this section as applicable to the NO_X emissions standard in table 1 to this subpart.

Commented [A26]: Equations to clarify how units with CEMS demonstrate compliance continuous compliance. The heat-input weighted average must be used for the lb/MWh and new lb/MMBtu options.

(1) For each 4-operating hour period, compute the 4-operating hour rolling average NO_X emissions as the heat input weighted average of the hourly average of NO_X emissions for a given operating hour and the 3 operating hours preceding that operating hour using the applicable equation in paragraph (g)(2) of this section. If the 4-operating hour period contains more than one operating hour with no data points (one or more continuous monitors was out-of-control for the entire hour), report the 4-operating hour rolling average NO_X emissions rate determined for the period as occurring during a period with monitor downtime.

(2) If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the 4-operating hour rolling average NO_X emissions rate and the applicable 4-operating hour rolling average NO_X emissions standard, calculated using hourly values from in table 1 to this subpart, using equation 5 to this subpart.

$$E = \frac{\sum_{i=1}^{4} (E_i \times Q_i)}{\sum_{i=1}^{4} Q_i} \quad \text{(Eq. 5)}$$

Where:

E = 4-operating hour rolling average NO_X emissions (lb/MMBtu or ng/J),
E_i = Hourly average NO_X emissions rate or emissions standard for operating hour “i” (lb/MMBtu or ng/J), and
Q_i = Total heat input to stationary combustion turbine for operating hour “i” (MMBtu or J as appropriate).

(h) For each combustion turbine demonstrating compliance on an output-based standard, you must determine excess emissions on a 30 operating-day rolling average basis. The measured emissions rate is the NO_X emissions measured by the CEMS for a given operating day and the 29 operating days preceding that day. Once each day, calculate a new 30-operating day average measured emissions rate using all hourly average values based on non out-of-control NO_X emission data for all operating hours during the previous 30-operating day operating period. Report any 30-operating day periods for which you have less than 90 percent data availability as monitor downtime. If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the measured emissions rate and emissions standard using equation 6 to this subpart. If you elect to comply with the applicable output-based emissions rate standard, calculate both the 30-operating day rolling average NO_X emissions rate and the applicable 30-operating day rolling average NO_X emissions standard, calculated using hourly values from in table 1 to this subpart, using equation 6 to this subpart.

$$E = \frac{\sum_{i=1}^{n}\left(E_i \times Q_i\right)}{\sum_{i=1}^{n} P_i} \quad \text{(Eq. 6)}$$

Where:

E = 30-operating day average NO_X measured emissions rate combustion turbines (lb/MWh or ng/J),

E_i = Hourly average NO_X emissions rate or emissions standard for non out-of-control operating hour "i" (lb/MMBtu or ng/J),

Q_i = Total heat input to stationary combustion turbine for non out-of-control operating hour "i" (MMBtu or J as appropriate),

P_i = Total gross or net energy output from stationary combustion turbine for non out-of-control operating hour "i" (MWh or J), and

n = Total number of operating non out-of-control hours in the 30 operating-day period.

§60.4360a How do I use fuel sulfur analysis to determine the total sulfur content of the fuel combusted in my stationary combustion turbine?

Commented [A27]: Heating value tests since SO2 standard is in lb/MMBtu. The initial sulfur test must measure all sulfur compounds, not just H2S.

(a) If you elect to demonstrate compliance with a SO_2 emissions standard according to §60.4333a(d)(2), the fuel analyses may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency as determined by the Administrator or delegated authority using the sampling frequency specified in §60.4370a.

(b) Representative fuel analysis samples may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287-97 (incorporated by reference, see §60.17) for gaseous fuels or ASTM D4177-95 (incorporated by reference, see §60.17) for liquid fuels. For reference purposes when manually collecting gaseous samples, see Gas Processors Association Standard 2166-17 (incorporated by reference, see §60.17). For reference purposes when manually collecting liquid samples, see either Gas Processors Association Standard 2174-14 or the procedures for manual pipeline sampling in section 14 of ASTM D4057-95 (both of which are incorporated by reference, see §60.17).

(c) Each collected fuel analysis sample must be analyzed for the total sulfur content of the fuel and heating value using the methods specified in paragraphs (c)(1) or (2) of this section, as applicable to the fuel type.

(1) For the sulfur content of liquid fuels, ASTM D129-00, or alternatively D1266-98, D1552-03, D2622-05, D4294-03, or D5453-05 (all of which are incorporated by reference, see §60.17). For the heating value of liquid fuels, ASTM D240-19 or D4809-18 (both of which are incorporated by reference, see §60.17); or

(2) For the sulfur content of gaseous fuels, ASTM D1072-90 (Reapproved 1999), or alternatively D3246-05, D4468-85, or D6667-04 (all of which are incorporated by reference, see §60.17). If the total sulfur content of the gaseous fuel during the most recent compliance demonstration was less than half the applicable standard, ASTM D4084-05, D4810-88, D5504-01, or 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. For the heating value of gaseous fuels, ASTM D1826-94 (Reapproved 2003), or alternatively D3588-98 (Reapproved 2003), D4891-99 (Reapproved 2006), or Gas Processors Association Standard 2172-09 (all of which are incorporated by

reference, see §60.17).

§60.4370a How frequently must I determine the fuel sulfur content?

(a) If you are complying with requirements in §60.4360a, the total sulfur content of all fuels combusted in each stationary combustion turbine subject to an SO_2 emissions standard in §60.4330a must be determined according to the schedule specified in paragraphs (a)(1) or (2) of this section, as applicable to the fuel type, unless you determine a custom schedule for the stationary combustion turbine according to paragraph (b) of this section.

(1) 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 in 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 liquid fuel already in the intended storage tank).

(2) If the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per operating day.

(b) As an alternative to the requirements of paragraph (a) of this section, you may implement 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 using the procedures provided in either paragraph (b)(1) and (2) of this section. Either you or the fuel vendor may perform the sampling. As an alternative to using one of these procedures, you may use a custom schedule that has been substantiated with data and approved by the Administrator or delegated authority as a change in monitoring prior to being used to comply with the applicable standard in §60.4330a.

(1) You may determine and implement a custom sulfur sampling schedule for your stationary combustion turbine using the procedure specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) Obtain daily total sulfur content measurements for 30 consecutive 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 must be as specified in paragraph (b)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals provided the fuel source or supplier does not change. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable standard, follow the procedures in paragraph (b)(1)(iii) of this section. If any measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section.

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

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

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

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

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

(2) You may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 in appendix D to part 75 of this chapter to determine and implement a sulfur sampling schedule for your stationary combustion turbine using the procedure specified in paragraphs (b)(2)(i) through (iii) of this section.

(i) If the maximum fuel sulfur content obtained from any of the 720 hourly samples does not exceed half the applicable standard, then the minimum required sampling frequency must be one sample at 12-month intervals.

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

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

§60.4372a How can I demonstrate compliance with my SO_2 emissions standard using records of the fuel sulfur content?

(a) If you elect to demonstrate compliance with a SO_2 emissions standard according to §60.4333a(d)(3), you must maintain on-site records (such as a current, valid purchase contract, tariff sheet, or transportation contract) documenting that total sulfur content for the fuel combusted in your stationary combustion turbine at all times does not exceed the conditions specified in paragraph (b) through (e) of this section, as applicable to your stationary combustion turbine.

(b) If your stationary combustion turbine is subject to the SO_2 emissions standard in §60.4330a(a), then the fuel combusted must have a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) heat input or less.

(c) If your stationary combustion turbine is subject to the SO_2 emissions standard in §60.4330a(b), then the total sulfur content of the gaseous fuel combusted must be 650 (mg/scm) (28 gr/100 scf).

(d) If your stationary combustion turbine is subject to the SO_2 emissions standard in §60.4330a(c) or (d), the total sulfur content of the fuel combusted must be:

(1) For natural gas, 140 gr/100 scf or less.

(2) For fuel oil, 0.40 weight percent (4,000 ppmw) or less.

(3) For other fuels, potential SO_2 emissions of 180 ng/J (0.42 lb/MMBtu) heat input or less.

(e) Representative fuel sampling data following the procedures specified in section 2.3.1.4 or 2.3.2.4 in appendix D to part 75 of this chapter documenting that the fuel meets the part 75 requirements to be considered either pipeline natural gas or natural gas.

§60.4374a How do I demonstrate compliance with my SO_2 emissions standard and determine excess emissions using a SO_2 CEMS?

Commented [A28]: Procedures to use a SO_2 CEMS.

(a) If you demonstrate continuous compliance using a CEMS for measuring SO_2 emissions, excess emissions are defined as the applicable averaging period, either 4-operating hour or 30-operating day, during which the average SO_2 emissions from your stationary combustion turbine measured by the CEMS exceeds the applicable SO_2 emissions standard specified in §60.4330a as determined using the procedures specified in this section that apply to your stationary combustion turbine.

(b) You must install, calibrate, maintain, and operate a CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations at the outlet of your stationary combustion turbine, and record the output of the system.

(c) The 1-hour average SO_2 emissions rate measured by a CEMS must be expressed in ng/J or lb/MMBtu heat input and must be used to calculate the average emissions rate under §60.4330a.

(d) You must use the procedures for installation, evaluation, and operation of the CEMS as specified in §60.13 and paragraphs (d)(1) through (3) of this section.

(1) Each CEMS must be operated according to the applicable procedures under Performance Specifications 1, 2, and 3 in appendix B of this part;

(2) Quarterly accuracy determinations and daily calibration drift tests must be performed according to Procedure 1 in appendix F of this part; and

(3) The span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the stationary combustion turbine if no SO_2 control device is used) must be 125 percent of either the highest applicable standard or highest potential SO_2 emissions rate of the fuel combusted.

(e) If you have installed and certified a SO_2 CEMS that meets the requirements of part 75 of this chapter, the Administrator or delegated authority can approve that only quality assured data from the CEMS must be used to identify excess emissions under this subpart. You must report periods where the missing data substitution procedures in subpart D of part 75 are applied as monitoring system downtime in the excess emissions and monitoring performance report required under §60.7(c).

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

(g) Calculate the hourly average SO_2 emissions rate, in units of the emissions standard under §60.4330a, using lb/MMBtu for units complying with the input-based standard or using equation 7 to this subpart for units complying with the output-based standard:

(1) For simple-cycle operation:

$$E = \frac{(SO_2)_h \times Q}{P} \quad \text{(Eq. 7)}$$

Where:

E =	Hourly SO_2 emissions rate, in lb/MWh,
$(SO_2)_h$ =	Average hourly SO_2 emissions rate, in lb/MMBtu,
Q =	Hourly heat input rate to the stationary combustion turbine, in MMBtu, measured using the fuel flow meter(s), *e.g.*, calculated using Equation D–15a in appendix D to part 75 of this chapter, an O_2 or CO_2 CEMS and a stack flow meter, or the methodologies in appendix F to part 75 of this chapter, and
P =	Gross or net energy output of the stationary combustion turbine in MWh.

(2) The gross or net energy output is calculated as the sum of the total electrical and mechanical energy generated by the stationary combustion turbine; the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generating unit; the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MWh, minus the auxiliary load as calculated using equations 8 and 9 to this subpart; and any auxiliary load.

$$P = \frac{(Pe)_t}{T} + \frac{(Pe)_c}{T} - Pe_A + P_s + P_o \quad \text{(Eq. 8)}$$

Where:

P =	Gross energy output of the stationary combustion turbine system in MWh,
$(Pe)_t$ =	Electrical or mechanical energy output of the stationary combustion turbine in MWh,
$(Pe)_c$ =	Electrical or mechanical energy output (if any) of the steam turbine in MWh,
Pe_A =	Electric energy used for any auxiliary loads in MWh,
P_s =	Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh, and
P_o =	Other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the stationary combustion turbine.
T =	Electric Transmission and Distribution Factor. Equal to 0.95 for CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of electric or direct mechanical output and 20.0 percent of the total gross useful energy output consists of useful thermal output on an annual basis. Equal to 1.0 for all other combustion turbines.

Commented [A29]: Subject to comment solicitation

$$P_s = \frac{Q_m \times H}{3.413 \times 10^6 \ Btu/MWh} \quad \text{(Eq. 9)}$$

Where:

P_s =	Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh,
Q_m =	Measured steam flow rate in lb,
H =	Enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and
3.413×10^6 =	Conversion factor from Btu to MWh.

(3) For mechanical drive applications complying with the output-based standard, use equation 10 to this subpart:

$$E = \frac{(SO_2)_m}{BL \times AL} \quad \text{(Eq. 10)}$$

Where:

E =	SO_2 emissions rate in lb/MWh,
$(SO_2)_m$ =	SO_2 emissions rate in lb/h,
BL =	Manufacturer's base load rating of turbine, in MW, and
AL =	Actual load as a percentage of the base load rating.

(h) For each stationary combustion turbine demonstrating compliance on a heat input-based emissions standard, excess SO_2 emissions are determined on a 4-operating hour averaging period basis using the SO_2 CEMS data and procedures specified in paragraphs (i)(1) and (2) of this section and as applicable to the SO_2 emission standard.

(1) For each 4-operating hour period, compute the 4-operating hour rolling average SO_2 emissions as the heat input weighted average of the hourly average of SO_2 emissions for a given operating hour and the 3 operating hours preceding that operating hour using the applicable equation in paragraph (i)(2) of this section. If the 4-operating hour period contains more than one operating hour with no data points (one or more continuous monitors was out-of-control for the entire hour), report the 4-operating hour rolling average SO_2 emissions rate determined for the period as occurring during a period of monitor downtime.

(2) If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the 4-operating hour rolling average SO_2 emissions rate and the applicable 4-operating hour rolling average SO_2 emission standard using equation 11 to this subpart.

$$E = \frac{\sum_{i=1}^{4} (E_i \times Q_i)}{\sum_{i=1}^{4} Q_i} \quad \text{(Eq. 11)}$$

Where:

E =	4-operating hour rolling average SO_2 emissions (lb/MMBtu or ng/J),
E_i =	Hourly average SO_2 emissions rate or emissions standard for operating hour "i" (lb/MMBtu or ng/J), and
Q_i =	Total heat input to stationary combustion turbine for operating hour "i" (MMBtu or J as appropriate).

(i) For each combustion turbine demonstrating compliance on an output-based standard, you must determine excess emissions on a 30-operating day rolling average basis. The measured emissions rate is the SO_2 emissions measured by the CEMS for a given operating day and the 29 operating days preceding that day. Once each day, calculate a new 30-operating day average measured emissions rate using all hourly average values based on non out-of-control SO_2 emission data for all operating hours during the previous 30-operating day operating period. Report any 30-operating day periods for which you have less than 90 percent data availability as monitor downtime. If you elect to comply with the applicable heat input-based emissions standard, calculate both the measured emissions rate and emissions standard using equation 12 to this subpart. If you elect to comply with the applicable output-based emissions rate standard, calculate both the 30-operating day rolling average SO_2 emissions rate and the applicable 30-operating day rolling average SO_2 emissions standard using equation 12 to this subpart.

$$E = \frac{\sum_{i=1}^{n} (E_i \times Q_i)}{\sum_{i=1}^{n} P_i} \quad \text{(Eq. 12)}$$

Where:

E = 30-operating day average SO_2 measured emissions rate (lb/MWh or ng/J),

E_i = Hourly average SO_2 measured emissions rate for non out-of-control operating hour "i" (lb/MMBtu or ng/J),

Q_i = Total heat input to stationary combustion turbine for non out-of-control operating hour "i" (MMBtu or J as appropriate),

P_i = Total gross energy output from stationary combustion turbine for non out-of-control operating hour "i" (MWh or J), and

n = Total number of non out-of-control operating hours in the 30 operating-day period.

(j) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-operating day rolling average basis.

Commented [A30]: Minimum data availability requirement

Recordkeeping and Reporting

§60.4375a What reports must I submit?

(a) An owner or operator of a stationary combustion turbine that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, must submit reports of excess emissions and monitor downtime, according to §60.7(c). Excess emissions must be reported for all periods of unit operation, including startup, shutdown, and malfunction.

(b) Within 60 days after the date of completing each performance test or continuous emissions monitoring systems (CEMS) performance evaluation that includes a relative accuracy test audit (RATA), you must submit the results following the procedures specified in paragraphs (b)(1) through (3) of this section.

(1) *Data collected using test methods and performance evaluations of CEMS measuring RATA pollutants that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test or performance evaluation.* Submit the results of the performance test or evaluation to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(2) *Data collected using test methods and performance evaluations of CEMS measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test or performance evaluation.* The results of the performance test or evaluations must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(3) *Confidential business information (CBI).*

(i) The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraph (b)(1) or (2) of this section, you must submit a complete file, including information claimed to be CBI, to the EPA.

(ii) The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website.

(iii) Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

(iv) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqps_cbi@epa.gov, and as described above, should include clear CBI markings and be flagged to the attention of the Group Leader, Measurement Policy Group. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqps_cbi@epa.gov to request a file transfer link.

(v) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 TW Alexander Dr., Research Triangle Park, North Carolina 27711, Attention Group Leader, Measurement Policy Group. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(vi) All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(vii) You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described in paragraphs (b)(1) and (2) of this section.

(4) *Forms used to submit information to CEDRI.* You must submit all other reports not subject to the requirements in paragraphs (b)(1) and (2) of this section using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (b) of this section. If the reporting form specific to this subpart is not available on the CEDRI website at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available on the CEDRI website for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The date reporting forms become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(c) The notification requirements of §60.8 apply to the initial and subsequent performance tests.

(d) An owner or operator of an affected facility complying with §60.4333a(b)(3) must notify the Administrator or delegated authority within 15 calendar days after the facility recommences operation.

(e) An owner or operator of an affected facility complying with §60.4333a(b)(4) must notify the Administrator or delegated authority within 15 calendar days after the facility has operated more than 50 operating hours since the date the previous performance test was required to be conducted.

(f) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (f)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(g) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure*, you must meet the requirements outlined in paragraphs (g)(1) through (5) of this section.

(1) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (e.g., hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (e.g., large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the *force majeure* event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.

(h) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

§60.4380a How are NO_X excess emissions and monitor downtime reported?

(a) For a stationary combustion turbine that uses water or steam to fuel ratio monitoring and is subject to the reporting requirements under §60.4375a(a), periods of excess emissions and monitor downtime must be reported as specified in paragraphs (a)(1) through (3) of this section.

(1) An excess emission that must be reported is any operating hour for which the 4-operating hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, is less than the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320a, as established during the most recent performance test. Any operating hour during which no water or steam is injected into the turbine when the specific conditions require water or steam injection for NO_X control will also be considered an excess emission.

(2) A period of monitor downtime that must be reported is any operating hour in which water or steam is injected into the turbine, but the parametric data needed to determine the steam or water to fuel ratio are unavailable or out-of-control.

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

(b) For reports required under §60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using a CEMS, excess emissions are reported as specified in paragraphs (b)(1) through (3) of this section.

(1) An excess emission that must be reported is any unit operating period in which the 4-operating hour or 30-operating day rolling average NO_X emissions rate exceeds the applicable emissions standard in §60.4320a as

determined in §60.4350a.

(2) A period of monitor downtime that must be reported is any operating hour in which the data for any of the following parameters are either missing or out-of-control: NO_X concentration, CO_2 or O_2 concentration, stack flow rate, heat input rate, steam flow rate, steam temperature, steam pressure, or megawatts. You are only required to monitor parameters used for compliance purposes.

(3) For hours with multiple emission standards, the applicable standard for that hour is determined based on the condition, excluding periods of monitor downtime, that corresponded to the highest emissions standard.

(c) For reports required under §60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using combustion parameters or parameters that document proper operation of the NO_X emission controls excess emissions and monitor downtime are reported as specified in paragraphs (c)(1) and (2) of this section.

(1) Excess emissions that must be reported are each 4-operating hour rolling average in which any monitored parameter (as averaged over the 4 operating-hour period) does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) Periods of monitor downtime that must be reported are each operating hour in which any of the required parametric data are either not recorded or are out-of-control.

§60.4385a How are SO_2 excess emissions and monitor downtime reported?

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

(1) For samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, excess emissions occur each 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 stationary combustion turbine exceeds the applicable standard and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur standard.

(2) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent, 0.15 weight percent, or 0.40 weight percent as applicable. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been combusted, you may resume using the as-delivered sampling option.

(3) 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.

(b) If you choose the option to maintain records of the fuel sulfur content, excess emissions are defined as any period during which you combust a fuel that you do not have appropriate fuel records or that fuel contains sulfur greater than the applicable standard.

(c) For reports required under §60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using a CEMS, excess emissions are reported as specified in paragraphs (c)(1) through (2) of this section.

(1) An excess emission that must be reported is any unit operating period in which the 4-operating hour or 30-operating day rolling average SO_2 emissions rate exceeds the applicable emissions standard in §60.4330a as determined in §60.4374a.

(2) A period of monitor downtime that must be reported is any operating hour in which the data for any of the following parameters are either missing or out-of-control: SO_2 concentration, CO_2 or O_2 concentration, stack flow rate, heat input rate, steam flow rate, steam temperature, steam pressure, or megawatts. You are only required to monitor parameters used for compliance purposes.

§60.4390a What records must I maintain?

(a) You must maintain records of your information used to demonstrate compliance with this subpart as specified in §60.7.

(b) An owner or operator of a stationary combustion turbine that uses the other fuels, part-load, or low temperature NO_X standards in the compliance demonstration must maintain concurrent records of the hourly heat input, percent load, ambient temperature, and emissions data as applicable.

(c) An owner or operator of a stationary combustion turbine that uses the tuning NO_X standard in the compliance demonstration must identify the hours on which the maintenance was performed and a description of the maintenance.

(d) An owner or operator of a stationary combustion turbine that demonstrates compliance using the output-based standard must maintain concurrent records of the total gross or net energy output and emissions data.

(e) An owner or operator of a stationary combustion turbine that demonstrates compliance using the water or steam to fuel ratio or a parameter continuous monitoring system must maintain continuous records of the appropriate parameters.

(f) An owner or operator of a stationary combustion turbine complying with the fuel-based SO_2 standard must maintain records of the results of all fuel analyses or a current, valid purchase contract, tariff sheet, or transportation contract.

§60.4395a When must I submit my reports?

Consistent with §60.7(c), all reports required under §60.7(c) must be electronically submitted via CEDRI by the 30th day following the end of each 6-month period.

Performance Tests

§60.4400a How do I conduct performance tests to demonstrate compliance with my NO_X emissions standard if I do not have a NO_X CEMS?

(a) You must conduct the performance test according to the requirements in §60.8 and paragraphs (b) through (d) of this section.

(b) You must use the methods in either paragraph (b)(1) or (2) of this section to measure the NO_X concentration for each test run.

(1) Measure the NO_X concentration using EPA Method 7E in appendix A-4 of this part or EPA Method 20 in appendix A-7 of this part. In addition, when only natural gas is being combusted ASTM D6522-20 (incorporated by reference, see §60.17) can be used instead of EPA Method 20 in appendix A-7 of this part to determine the oxygen content in the exhaust gas. For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A-1 of this part, and measure and record the electrical and thermal output from the unit. Then, use equation 13 to this subpart to calculate the NO_X emissions rate:

$$E = \frac{1.194 \times 10^{-7} \times (NO_x)_c \times Q_{std}}{P} \quad \text{(Eq. 13)}$$

Where:

E =	NO_X emissions rate, in lb/MWh,
1.194×10^{-7} =	Conversion constant, in lb/dscf-ppm,
$(NO_x)_c$ =	Average NO_X concentration for the run, in ppm,
Q_{std} =	Average stack gas volumetric flow rate, in dscf/h, and
P =	Average gross or net electrical and mechanical energy output of the stationary combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for CHP operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation or to enhance the performance of the stationary combustion turbine, in MW, calculated according to §60.4350a.

(2) Measure the NO_X and diluent gas concentrations, using either EPA Method 7E in appendix A-4 of this part and EPA Method 3A in appendix A-2 of this part, or EPA Method 20 in appendix A-7 of this part. In addition,

when only natural gas is being combusted ASTM D6522-20 (incorporated by reference, see §60.17) can be used instead of EPA Method 3A in appendix A-2 of this part or EPA Method 20 in appendix A-7 of this part to determine the oxygen content in the exhaust gas. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), an O_2 or CO_2 CEMS along with a stack flow meter, or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output-based standard measure the electrical, mechanical, and thermal output of the unit. Use EPA Method 19 in appendix A-7 of this part to calculate the NO_X emissions rate in lb/MMBtu. Then, use equations 1 and, if necessary, 2 and 3 to this subpart in §60.4350a(f) to calculate the NO_X emissions rate in lb/MWh.

(c) You must use the methods in either paragraph (c)(1) or (2) of this section to select the sampling traverse points for NO_X and (if applicable) diluent gas.

(1) You must select the sampling traverse points for NO_X and (if applicable) diluent gas according to EPA Method 20 in appendix A-7 of this part or EPA Method 1 in appendix A-1 of this part (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(2) As an alternative to paragraph (c)(1) of this section, you may select the sampling traverse points for NO_X and (if applicable) diluent gas according to requirements in paragraphs (c)(2)(i) and (ii) of this section.

(i) You perform a stratification test for NO_X and diluent pursuant to the procedures specified in section 6.5.6.1(a) through (e) in appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you use the following alternative sample point selection criteria for the performance test specified in paragraphs (c)(2)(ii)(A) through (C) of this section.

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

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

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

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

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

(2) For a combined cycle or CHP combustion turbine with supplemental heat (duct burner), you must measure the total NO_X emissions downstream of the duct burner. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335a, then that monitoring system must be operated concurrently with each EPA Method 20 in appendix A-7 of this part or EPA Method 7E in appendix A-4 of this part run and must be used to determine the fuel consumption and the steam or water to fuel

ratio necessary to comply with the applicable §60.4320a NO_X emissions standard.

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

(5) The ambient temperature must be greater than 0 °F during the performance test. The Administrator or delegated authority may approve performance testing below 0 °F if the timing of the required performance test and environmental conditions make it impractical to test at ambient conditions greater than 0 °F.

Commented [A31]: Allow permitting authority to account for site specific conditions and approve testing below 0 °F in special circumstances

§60.4405a How do I conduct a performance test if I use a NO_X CEMS?

(a) If you use a CEMS the performance test must be performed according to the procedures specified in paragraph (b) of this section.

(b) The initial performance test must use the procedure specified in paragraphs (b)(1) through (4) of this section.

(1) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of the base load rating. You may perform testing at the highest achievable load point, if at least 75 percent of the base load rating cannot be achieved in practice. The ambient temperature must be greater than 0 °F during the RATA runs. The Administrator or delegated authority may approve performance testing below 0 °F if the timing of the required performance test and environmental conditions make it impractical to test at ambient conditions greater than 0 °F.

(2) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output-based standard, measure the electrical and thermal output from the unit.

(3) Use the test data both to demonstrate compliance with the applicable NO_X emissions standard under §60.4320a and to provide the required reference method data for the RATA of the CEMS described under §60.4342a.

(4) Compliance with the applicable emissions standard in §60.4320a is achieved if the sum of the NO_X emissions divided by the heat input (or gross or net energy output) for all the RATA runs, expressed in units of lb/MMBtu or lb/MWh, does not exceed the emissions standard.

§60.4415a How do I conduct performance tests to demonstrate compliance with my SO_2 emissions standard?

(a) An owner or operator of an affected facility complying with the fuel-based standard must submit fuel records (such as a current, valid purchase contract, tariff sheet, transportation contract, or results of a fuel analysis) to satisfy the requirements of §60.8.

Commented [A32]: Fuel tariffs satisfy the initial and ongoing performance testing requirements

(b) An owner or operator of an affected facility complying with the SO_2 emissions standard must conduct the performance test by measuring the SO_2 emissions in the stationary combustion turbine exhaust gases using the methods in either paragraph (b)(1) or (2) of this section.

(1) Measure the SO_2 concentration using EPA Methods 6, 6C, 8 in appendix A-4 of this part, or EPA Method 20 in appendix A-7 of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Method 6 in appendix A-4 of this part or EPA Method 20 in appendix A-7 of this part. For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A-1 of this part, and measure and record the electrical and thermal output from the unit. Then use equation 14 to this subpart to calculate the SO_2 emissions rate:

$$E = \frac{1.664\times10^{-7} \times (SO_2)_c \times Q_{std}}{P} \quad \text{(Eq. 14)}$$

Where:

E = SO_2 emissions rate, in lb/MWh,

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

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

Q_{std} = Average stack gas volumetric flow rate, in dscf/h, and

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

(2) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 in appendix A-4 of this part and EPA Method 3A in appendix A-2 of this part, or EPA Method 20 in appendix A-7 of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), an O_2 or CO_2 CEMS along with a stack flow meter, or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output based standard measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A-7 of this part to calculate the SO_2 emissions rate in lb/MMBtu. Then, use equations 7 and, if necessary, 8 and 9 to this subpart in §60.4374a to calculate the SO_2 emissions rate in lb/MWh.

Other Requirements and Information

Commented [A33]: If included in the final rule, the Title V permitting exemption would be included in this section

§60.4416a What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§60.1 through 60.19, listed in table 2 to this subpart, do not apply to your affected combustion turbine.

§60.4417a Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or Tribal agency. If the Administrator has delegated authority to your state, local, or Tribal agency, then that agency, (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or Tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (6) of this section and does not transfer them to the state, local, or Tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emissions standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under §60.8(b).

(6) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

§60.4420a What definitions apply to this subpart?

Commented [A34]: Depending on comment solicitation, may add definitions for:
- Temporary combustion turbine
- garrison facility
- fire-fighting turbine
- system emergency

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

Annual capacity factor means the ratio between the actual heat input to a stationary combustion turbine during a calendar year and the potential heat input to the stationary combustion turbine had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.,* solar thermal) are not included when calculating the annual capacity factor.

Base load rating means 100 percent of the manufacturer's design heat input capacity of the combustion turbine engine at ISO conditions using the higher heating value of the fuel.

Base load combustion turbine means a stationary combustion turbine that has a 12-calendar month capacity factor of greater than 40 percent.

Biogas means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO_2.

By-product means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas and fuel oil) and combusted in a stationary combustion turbine. Gaseous substances with CO_2 levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not by-product.

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

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

Combustion turbine engine means the air compressor, combustor, and turbine sections of a stationary combustion turbine.

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

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

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 or 2, as defined in ASTM D396-98 (incorporated by reference, see §60.17), diesel fuel oil numbers 1 or 2, as defined in ASTM D975-08a (incorporated by reference, see §60.17), kerosene, as defined in ASTM D3699-08 (incorporated by reference, see §60.17), biodiesel as defined in ASTM D6751-11b (incorporated by reference, see §60.17), or biodiesel blends as defined in ASTM D7467-10 (incorporated by reference, see §60.17).

Dry standard cubic foot (dscf) means the quantity of gas, free of uncombined water, that would occupy a volume of 1 cubic foot at 293 Kelvin (20 °C, 68 °F) and 101.325 kPa (14.69 psi, 1 atm) of pressure.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases. No additional oxygen is used in a duct burner beyond what is inherent in the exhaust from the initial source.

Commented [A35]: You cannot have a large boiler with additional air input following a small turbine.

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

Excess emissions means a specified averaging period over which either (1) the NO_X or SO_2 emissions rate are higher than the applicable emissions standard in §60.4320a or §60.4330a; (2) the total sulfur content of the fuel being combusted in the affected facility or the SO_2 emissions exceeds the standard specified in §60.4330a; or (3) the recorded value of a particular monitored parameter, including the water or steam to fuel ratio, is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator or delegated authority, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24

Fuel oil means a fluid mixture of hydrocarbons that maintains a liquid state at ISO conditions. Additionally, fuel oil must meet the definition of either distillate oil (as defined in this subpart) or liquefied petroleum (LP) gas as defined in ASTM D1835-03a.

Gross energy output means:

(1) For simple cycle and combined cycle combustion turbines, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s).

(2) For a CHP combustion turbine, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) plus any useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process).

(3) For a CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of electric or direct mechanical output and 20.0 percent of the total gross useful energy output consists of useful thermal output on an annual basis, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) divided by 0.95 plus any useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process).

Heat recovery steam generating unit (HRSG) means a unit where the hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners. A heat recovery steam generating unit operating independent of the combustion turbine engine may operate burners using ambient air.

Integrated gasification combined cycle electric utility steam generating unit (IGCC) means an electric utility steam generating unit that combusts solid-derived fuels in a combined-cycle combustion turbine. No solid fuel is directly combusted in the unit during operation.

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity, and 101.325 kilopascals (14.69 psi, 1 atm) pressure.

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

Low-Btu gas means biogas or any gas with a heating value of less than 26 megajoules per standard cubic meter (MJ/scm) (700 Btu/scf).

Natural gas means a fluid mixture of hydrocarbons, composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 MJ/scm (950 and 1,100 Btu/scf), that maintains a gaseous state under ISO conditions. In addition, natural gas contains 460 mg/scm (20.0 gr/100 scf) or less of total sulfur. Unless processed to meet the definition of natural gas, 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 CO_2 content or heating value. Mixtures of natural gas and up to 30 percent (by volume) hydrogen are considered natural gas regardless of the overall percent methane and heating value of the fuel.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected turbine divided by 0.95, plus 100 percent of the useful thermal output.

Commented [A36]: Subject to comment solicitation

Commented [A37]: Definition of low btu gas includes blast furnace gas, coke oven gas, etc.
Digester gas can have a heating value of slightly more than 600 Btu/scf to account for variability value is set at 700 Btu/scf (HHV).

Commented [A38]: Combustion turbines co-firing up to 30% hydrogen would be subcategorized and natural gas-fired combustion turbines.

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Noncontinental area means Guam, American Samoa, the Northern Mariana Islands, or offshore platforms.

Offshore turbine means a stationary combustion turbine located on a platform in an ocean.

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.

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, the operating hour is a full operating hour. If the unit combusts fuel for only part of the clock hour, the operating hour is a partial operating hour.

Out-of-control period means any period beginning with the hour corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit that indicates that the instrument is not measuring and recording within the applicable performance specifications and ending with the hour corresponding to the completion of an additional calibration error, linearity check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the applicable performance specifications.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine engine exhaust gases for purposes other than enhancing the performance of the stationary combustion turbine itself.

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Stationary combustion turbine means all equipment including, but not limited to, the combustion turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except post combustion emissions control equipment), heat recovery system (including heat recovery steam generators and duct burners); steam turbine; fuel compressor, heater, and/or pump, post-combustion emission control technology, any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system; plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine (*e.g*., onsite photovoltaics), integrated energy storage (*e.g*., onsite batteries), heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Standard cubic foot (scf) means the quantity of gas that would occupy a volume of 1 cubic foot at 293 Kelvin (20.0 °C, 68 °F) and 101.325 kPa (14.69 psi, 1 atm) of pressure.

Standard cubic meter (scm) means the quantity of gas that would occupy a volume of 1 cubic meter at 293 Kelvin (20.0 °C, 68 °F) and 101.325 kPa (14.69 psi, 1 atm) of pressure.

Turbine tuning means planned maintenance or parameter performance testing of a combustion turbine engine involving adjustment of the operating configuration to maintain proper combustion dynamics or testing machine operating performance. Turbine tuning is limited to 30 hours annually.

Useful thermal output means the thermal energy made available for use in any heating application (e.g., steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation or mechanical output at the affected facility to directly enhance the performance of the affected facility (*e.g*., economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output) or to supply energy to a pollution control device at the affected facility (*e.g*., steam provided to a carbon capture system would not be considered useful thermal output). Useful thermal output for affected facilities with no condensate return (or other thermal energy input to affected facilities) or where measuring the energy in the condensate (or other thermal energy input to the affected facilities) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions (*e.g*. liquid water). Affected facilities with meaningful energy in the condensate return (or other thermal energy input to the affected facility) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 or part 60 of this chapter as applicable. For CEMS maintained according to part 75, the initial certification requirements in 40 CFR 75.20 and appendix A to 40 CFR part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to 40 CFR part 75 must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to 40 CFR part 75 must be met. For fuel flow meters maintained according to part 75, the initial certification requirements in section 2.1.5 of appendix D to 40 CFR part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to 40 CFR part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to 40 CFR part 75 apply (except for qualifying commercial billing meters). Any data not valid is considered out-of-control data.

Table 1 to Subpart KKKKa of Part 60 - Nitrogen Oxide Emission Standards for Stationary Combustion Turbines

Note: all numerical values have two significant figures

Combustion Turbine Type	**Combustion Turbine Fuel**	**Input-Based NOx Emission Standard**	**Optional Output-Based NO_X Standard**
Combustion Turbines Operating Above 70 Percent of the Base Load Rating			
New or reconstructed, low to intermediate load with base load rating ≤ 250 MMBtu/h	Natural gas	40 ng/J (0.092 lb/MMBtu)	0.35 kg/MWh-gross (0.76 lb/MWh-gross) 0.35 kg/MWh-net (0.78 lb/MWh-net)
	Non-natural gas	120 ng/J (0.29 lb/MMBtu)	1.4 kg/MWh-gross (3.0 lb/MWh-gross) 1.4 kg/MWh-net (3.1 lb/MWh-net)
New or reconstructed, base load with base load rating ≤ 250 MMBtu/h	Natural gas	4.8 ng/J (0.011 lb/MMBtu)	0.035 kg/MWh-gross (0.076 lb/MWh-gross) 0.035 kg/MWh-net (0.078 lb/MWh-net)
	Non-natural gas	15 ng/J (0.035 lb/MMBtu)	0.16 kg/MWh-gross (0.36 lb/MWh-gross) 0.17 kg/MWh-net (0.37 lb/MWh-net)
Modified, all loads with base load rating ≤ 250 MMBtu/h	Natural gas	40 ng/J (0.092 lb/MMBtu)	0.35 kg/MWh-gross (0.76 lb/MWh-gross) 0.35 kg/MWh-net (0.78 lb/MWh-net)
	Non-natural gas	120 ng/J (0.29 lb/MMBtu)	1.4 kg/MWh-gross (3.0 lb/MWh-gross) 1.4 kg/MWh-net (3.1 lb/MWh-net)
New or reconstructed low load with base load rating > 250 MMBtu/h and ≤ 850 MMBtu/h	Natural gas	40 ng/J (0.092 lb/MMBtu)	0.35 kg/MWh-gross (0.76 lb/MWh-gross) 0.35 kg/MWh-net (0.78 lb/MWh-net)
	Non-natural gas	120 ng/J (0.29 lb/MMBtu)	1.4 kg/MWh-gross (3.0 lb/MWh-gross) 1.4 kg/MWh-net (3.1 lb/MWh-net)
New or reconstructed, intermediate load or base load with base load rating > 250 MMBtu/h and ≤ 850 MMBtu/h	Natural gas	4.8 ng/J (0.011 lb/MMBtu)	0.035 kg/MWh-gross (0.076 lb/MWh-gross) 0.035 kg/MWh-net (0.078 lb/MWh-net)
	Non-natural gas	15 ng/J (0.035 lb/MMBtu)	0.16 kg/MWh-gross (0.36 lb/MWh-gross) 0.17 kg/MWh-net (0.37 lb/MWh-net)
Modified, all loads with base load rating > 250 MMBtu/h and ≤ 850 MMBtu/h	Natural gas	40 ng/J (0.092 lb/MMBtu)	0.35 kg/MWh-gross (0.76 lb/MWh-gross) 0.35 kg/MWh-net (0.78 lb/MWh-net)
	Non-natural gas	120 ng/J (0.29 lb/MMBtu)	1.4 kg/MWh-gross (3.0 lb/MWh-gross) 1.4 kg/MWh-net (3.1 lb/MWh-net)
New, modified, or reconstructed, low load with base load rating > 850 MMBtu/h	Non-natural gas	24 ng/J (0.055 lb/MMBtu)	0.24 kg/MWh-gross (0.53 lb/MWh-gross) 0.25 kg/MWh-net (0.55 lb/MWh-net)
	Non-natural gas	64 ng/J (0.15 lb/MMBtu)	0.70 kg/MWh-gross (1.6 lb/MWh-gross) 0.72 kg/MWh-net (1.6 lb/MWh-net
New, modified, or reconstructed, intermediate or base load with base load rating > 850 MMBtu/h	Natural gas	4.8 ng/J (0.011 lb/MMBtu)	0.035 kg/MWh-gross (0.076 lb/MWh-gross) 0.035 kg/MWh-net (0.078 lb/MWh-net)
	Non-natural gas	8.2 ng/J (0.019 lb/MMBtu)	0.089 kg/MWh-gross (0.20 lb/MWh-gross) 0.091 kg/MWh-net (0.20 lb/MWh-net)
New, modified, or reconstructed offshore combustion turbines, all sizes and loads	Natural gas	40 ng/J (0.092 lb/MMBtu)	0.35 kg/MWh-gross (0.76 lb/MWh-gross) 0.35 kg/MWh-net (0.78 lb/MWh-net)
	Non-natural gas	120 ng/J (0.29 lb/MMBtu)	1.4 kg/MWh-gross (3.0 lb/MWh-gross) 1.4 kg/MWh-net (3.1 lb/MWh-net)
Combustion Turbines Operating at 70 Percent of Less of the Base Load Rating and Other Specified Conditions			
Combustion turbines with	Natural gas	250 ng/J	2.7 kg/MWh-gross (6.0 lb/MWh-gross)

base load rating ≤ 250 MMBtu/h operating at 70 percent or less of the base load rating, sites north of the Arctic Circle, and/or ambient temperatures of less than 0 °F	or non-natural gas	(0.58 lb/MMBtu)	2.8 kg/MWh-net (6.1 lb/MWh-net)
Combustion turbines with base load rating > 250 MMBtu/h operating at 70 percent or less of the base load rating, sites north of the Arctic Circle, and/or ambient temperatures of less than 0 °F	Natural gas or non-natural gas	160 ng/J (0.37 lb/MMBtu)	1.7 kg/MWh-gross (3.8 lb/MWh-gross) 1.8 kg/MWh-net (3.9 lb/MWh-net)
Heat recovery units operating independent of the combustion turbine(s)	Natural gas or non-natural gas	90 ng/J (0.21 lb/MMBtu)	1.0 kg/MWh-gross (2.2 lb/MWh-gross) 1.0 kg/MWh-net (2.2 lb/MWh-net)

Table 2 to Subpart KKKKa of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart KKKKa

General provisions citation	Subject of citation	Applies to subpart KKKKa	Explanation
§60.1	Applicability	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4420a.
§60.3	Units and Abbreviations	Yes	
§60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in §60.7(a)(1) and (3) and to keep records of malfunctions in §60.7(b), if applicable.
§60.8(a)	Performance tests	Yes	
§60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods

§60.8(c) – (f)	Conducting performance tests	Yes	
§60.9	Availability of Information	Yes	
§60.10	State authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	
§60.12	Circumvention	Yes	
§60.13 (a) – (h), (j)	Monitoring requirements	Yes	
§60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	No	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	Yes	
§60.19	General notification and reporting requirements	Yes	Does not apply to notifications under §75.61 or to information reported through ECMPS.