**IN THE UNITED STATES COURT OF APPEALS**
**FOR THE DISTRICT OF COLUMBIA CIRCUIT**

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| SIERRA CLUB,<br>AMERICAN LUNG ASSOCIATION,<br>CLEAN WISCONSIN, CITIZENS FOR PENNSYLVANIA'S FUTURE,<br>ENVIRONMENTAL DEFENSE FUND,<br>and NATURAL RESOURCES DEFENSE COUNCIL, INC.,<br><br>Petitioners,<br><br>v.<br><br>UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and LEE ZELDIN, Administrator, U.S. Environmental Protection Agency,<br><br>Respondents. | Case No. ___________ |

**PETITION FOR REVIEW**

Pursuant to Clean Air Act Section 307(b)(1), 42 U.S.C. § 7607(b)(1); Federal Rule of Appellate Procedure 15(a); and D.C. Circuit Rule 15(a)(1), Sierra Club, American Lung Association, Clean Wisconsin, Citizens for Pennsylvania's Future, Environmental Defense Fund, and Natural Resources Defense Council, Inc., hereby petition this Court for review of a final action taken by Respondents United States Environmental Protection Agency and Lee Zeldin, Administrator, United States Environmental Protection Agency, entitled "New Source Performance Standards Review for Stationary Combustion Turbines and Stationary Gas Turbines" and published in the Federal Register at 91 Fed. Reg. 1910 (Jan. 15, 2026). A copy of EPA's final action is attached to this petition.

DATED: March 16, 2026

Respectfully submitted,

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## CORPORATE DISCLOSURE STATEMENT

Pursuant to Federal Rule of Appellate Procedure 26.1 and D.C. Circuit Rule 26.1, Sierra Club, American Lung Association, Clean Wisconsin, Citizens for Pennsylvania's Future, Environmental Defense Fund, and Natural Resources Defense Council, Inc., ("Petitioners") make the following disclosures:

Petitioners are nonprofit environmental and public health organizations. Petitioners do not have any parent corporations, and no publicly held corporation has a ten percent or greater ownership interest in any of them.

DATED: March 16, 2026

Respectfully submitted,


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## CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing Petition for Review have been served by United States first-class mail this 16th day of March, 2026, upon the following:

Administrator Lee Zeldin
U.S. Environmental Protection Agency
Office of the Administrator – 1101A
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Washington, D.C. 20460

Pamela Bondi
Attorney General
U.S. Department of Justice
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Washington, D.C. 20530

U.S. Environmental Protection Agency
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1200 Pennsylvania Avenue, NW
Washington, D.C. 20460

Respectfully submitted,

*/s/ Megan M. Herzog*
Megan M. Herzog

# ATTACHMENT

## ENVIRONMENTAL PROTECTION AGENCY

### 40 CFR Part 60

**[EPA–HQ–OAR–2024–0419; FRL–11542–02–OAR]**

**RIN 2060–AW21**

## New Source Performance Standards Review for Stationary Combustion Turbines and Stationary Gas Turbines

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Final rule.

**SUMMARY:** The U.S. Environmental Protection Agency (EPA, or Agency) is finalizing amendments to the new source performance standards (NSPS) for stationary combustion turbines and stationary gas turbines pursuant to a review required by the Clean Air Act (CAA). As a result of this review, the EPA is establishing subcategories for new, modified, or reconstructed stationary combustion turbines based on size, rates of utilization, design efficiency, and fuel type. The EPA determined that combustion controls are the best system of emission reduction (BSER) for nitrogen oxide ($NO_X$) emissions for most new, modified, or reconstructed stationary combustion turbines. For one subcategory, the BSER for $NO_X$ is combustion controls with the addition of selective catalytic reduction (SCR). The EPA further determined that the BSER for sulfur dioxide ($SO_2$) emissions has not changed since the last NSPS review. Based on these determinations, the Agency is promulgating standards of performance in a new subpart of the Code of Federal Regulations (CFR). The Agency is also adding a subcategory for stationary combustion turbines that are used in temporary applications, exempting certain sources from title V requirements, and finalizing other provisions. The EPA is finalizing amendments to existing regulations to address or clarify specific technical and editorial issues.

**DATES:** This final rule is effective on January 15, 2026. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of January 15, 2026. The incorporation by reference of certain other material listed in the rule was approved by the Director of the Federal Register as of July 8, 2004, and July 6, 2006.

**ADDRESSES:** The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2024–0419. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only as portable document format (PDF) versions that can only be accessed on the EPA computers in the docket office reading room. Certain databases and physical items cannot be downloaded from the docket but may be requested by contacting the docket office at (202) 566–1744. The docket office has up to 10 business days to respond to these requests. Except for such material, all documents are available electronically in *Regulations.gov* or on the EPA computers in the docket office reading room at the EPA Docket Center, WJC West Building, Room Number 3334, 1301 Constitution Ave. NW, Washington, DC. The Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

**FOR FURTHER INFORMATION CONTACT:** For information about this final rule, contact John Ashley, Industrial Processing and Power Division (D243–02), Office of Clean Air Programs, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, North Carolina 27711; telephone number: (919) 541–1458; and email address: *ashley.john@epa.gov.*

**SUPPLEMENTARY INFORMATION:**

*Preamble acronyms and abbreviations.* Throughout this document the use of ''we,'' ''us,'' or ''our'' is intended to refer to the EPA. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ANSI American National Standards Institute
ASME American Society of Mechanical Engineers
ASTM American Society for Testing and Materials
BPT benefit-per-ton
BSER best system of emission reduction
Btu British thermal unit
CAA Clean Air Act
CAMPD Clean Air Markets Program Data
CBI Confidential Business Information
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CEMS continuous emissions monitoring system
CFR Code of Federal Regulations
CHP combined heat and power
CMS continuous monitoring system
CO carbon monoxide
$CO_2$ carbon dioxide
DLE dry low-emission
DLN dry low-$NO_X$
EIA Economic Impact Analysis
EPA Environmental Protection Agency
ERT Electronic Reporting Tool
FR Federal Register
GE General Electric
GHG greenhouse gas
GJ gigajoule(s)
gr grains
HAP hazardous air pollutant
HHV higher heating value
HRSG heat recovery steam generator
ICR information collection request
ISA Integrated Science Assessment
kW kilowatt
LAER lowest achievable emission rate
LCOE levelized cost of electricity
lb/MWh pounds per megawatt-hour
lb/MMBtu pounds per million British thermal units
MJ megajoules
MMBtu/h million British thermal units per hour
MW megawatt
MWh megawatt-hour
NAICS North American Industry Classification System
NEI National Emissions Inventory
NESHAP national emission standards for hazardous air pollutants
NETL National Energy Technology Laboratory
ng/J nanograms per joule
$NO_X$ nitrogen oxide
NSPS new source performance standards
NSR New Source Review
NSSN National Standards System Network
NTTAA National Technology Transfer and Advancement Act
$O_2$ oxygen gas
O&M operating and maintenance
OEM original equipment manufacturers
OMB Office of Management and Budget
PDF portable document format
PM particulate matter
$PM_{2.5}$ particulate matter (diameter less than or equal to 2.5 micrometers)
ppm parts per million
ppmv parts per million by volume
ppmvd parts per million by volume dry
ppmw parts per million by weight
PRA Paperwork Reduction Act
PSD Prevention of Significant Deterioration
RATA relative accuracy test audit
RFA Regulatory Flexibility Act
RICE reciprocating internal combustion engines
scf standard cubic feet
scm standard cubic meter
SCR selective catalytic reduction
$SO_2$ sulfur dioxide
SSM startup, shutdown, and malfunction
ULSD ultra-low-sulfur diesel
UMRA Unfunded Mandates Reform Act
U.S.C. United States Code
VCS voluntary consensus standard

VOC volatile organic compound(s)

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## I. General Information

### *A. Does this action apply to me?*

The source category that is the subject of this final action is composed of stationary combustion turbines and stationary gas turbines regulated under CAA section 111. Based on the number of sources of stationary combustion turbines listed in the 2020 National Emissions Inventory (NEI), most, but not all, are accounted for by the following 2022 North American Industry Classification System (NAICS) codes. These include 2111 (Oil and Gas Extraction), 2211 (Electric Power Generation, Transmission, and Distribution), 2212 (Natural Gas Distribution), 3251 (Basic Chemical Manufacturing), 4862 (Pipeline Transportation of Natural Gas), and 518210 (Data Processing, Hosting, and Related Services). The NAICS codes serve as a guide for readers outlining the types of entities that this final action is likely to affect.

The NSPS codified in 40 CFR part 60, subpart KKKKa, are directly applicable to affected facilities that began construction, modification, or reconstruction after December 13, 2024. Federal, State, local, and Tribal government entities that own and/or operate stationary combustion turbines subject to 40 CFR part 60, subpart KKKKa, are affected by these amendments and standards. If you have any questions regarding the applicability of this action to a particular entity, you should carefully examine the applicability criteria found in 40 CFR part 60, subparts GG, KKKK, and KKKKa, and consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section of this preamble, your State air pollution control agency with delegated authority for NSPS, or your EPA Regional Office.

### *B. Where can I get a copy of this document and other related information?*

In addition to being available in the docket, an electronic copy of this final action is available on the internet at *https://www.epa.gov/stationary-sources-air-pollution/stationary-gas-and-combustion-turbines-new-source-performance.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the final rule and key technical documents at this same website.

### *C. Judicial Review and Administrative Review*

Under CAA section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by March 16, 2026. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

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

## II. Background

### *A. What is the statutory authority for this final action?*

The EPA's authority for this final rule is CAA section 111, which governs the establishment of standards of performance for stationary sources. CAA section 111(b)(1)(A) requires the EPA Administrator to promulgate a list of categories of stationary sources that the Administrator, ''in his judgment,'' finds ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' The EPA has the authority under this section to define the scope of the source categories; to determine, consistent with the statutory requirements, the pollutants for which standards should be developed; and to distinguish among classes, types, and sizes within categories in establishing the standards.[1] Once the EPA lists a source category that contributes significantly to dangerous air pollution, the EPA must, under CAA section 111(b)(1)(B), establish ''standards of performance'' for ''new sources'' in the source category. These standards are referred to as new source performance standards, or NSPS. The NSPS are national requirements that apply directly to the sources subject to them.

Under CAA section 111(a)(1), a ''standard of performance'' is defined as ''a standard for emissions of air pollutants'' that is determined in a specified manner. When the EPA establishes or revises a performance standard, CAA section 111(a)(1) provides that such standard must ''reflect[ ] the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' Thus, the term ''standard of performance'' as used in CAA section 111 makes clear that the EPA must determine both the ''best system of emission reduction . . . adequately demonstrated'' (BSER) for emissions of the relevant air pollutants by regulated sources in the source category and the ''degree of emission limitation achievable through the application of the [BSER].'' [2] As explained further below, to determine the BSER, the EPA first identifies the ''system[s] of emission reduction'' that are ''adequately demonstrated,'' and then determines the ''best'' of those adequately demonstrated systems, ''taking into account'' factors including ''cost,'' ''nonair quality health and environmental impact,'' and ''energy requirements.'' The EPA then derives from that system an ''achievable'' ''degree of emission limitation.'' The EPA must then, under CAA section 111(b)(1)(B), promulgate ''standard[s] for emissions''—the NSPS—that reflect that level of stringency. The EPA may determine that different sets of sources have different characteristics relevant for determining the BSER for emissions of the relevant air pollutants and may subcategorize sources accordingly.[3] CAA section 111(b)(5) generally precludes the EPA from prescribing a particular technological system that must be used to comply with a standard of performance. Rather, sources can select any measure or combination of measures that will achieve the standard.

Pursuant to the definition of new source in CAA section 111(a)(2), standards of performance apply to facilities that begin construction, modification, or reconstruction after the date of publication of the proposed standards in the **Federal Register**. Under CAA section 111(a)(4), ''modification'' means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Changes to an existing facility that do not result in an increase in emissions are not considered modifications. Under the provisions in 40 CFR 60.15, reconstruction means the replacement of components of an existing facility such that: (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and (2) it is technologically and economically feasible to meet the applicable standards. Pursuant to CAA section 111(b)(1)(B), the standards of performance or revisions thereof shall become effective upon promulgation.

1. Key Elements of Determining a Standard of Performance

Congress first defined the term ''standard of performance'' when enacting CAA section 111 in the 1970 Clean Air Act, amended the definition in the Clean Air Act Amendments (CAAA) of 1977, and then amended the definition again in the 1990 CAAA to largely restore the definition as it read in the 1970 CAA. The D.C. Circuit has reviewed CAA section 111 rulemakings on numerous occasions since 1973 and has developed a body of caselaw that interprets the term.[4]

The basis for standards of performance is the ''degree of emission limitation'' that is ''achievable'' by sources in the source category by application of the ''best system of emission reduction'' that the EPA determines is ''adequately demonstrated'' (BSER). As explained further below in this section, the D.C. Circuit has explained that systems are not ''adequately demonstrated'' if they are ''purely theoretical or experimental.'' [5] The D.C. Circuit has stated that in determining the ''best'' adequately demonstrated system for the pollutants at issue, the EPA must also take into account ''the amount of air pollution'' reduced.[6] The D.C. Circuit has also stated that the EPA may weigh the various factors identified in the statute and caselaw to determine the ''best'' system and has emphasized that the EPA has significant discretion in weighing the factors.[7]

After determining the BSER, the EPA sets an achievable emission limit based on application of the BSER.[8] For a CAA section 111(b) rule, the EPA determines the standard of performance that reflects the achievable emission limit. For a CAA section 111(d) rule, the States have the obligation of establishing standards of performance for the affected sources that reflect the degree of emission limitation that the EPA has determined and provided to States as part of an emission guideline. In applying these standards to existing sources, States are permitted to take a source's remaining useful life and other factors into account.

In identifying ''system[s] of emission reduction, the EPA has historically followed a ''technology-based approach'' that focuses on ''measures that improve the pollution performance of individual sources,'' such as ''add-on controls.'' [9] The EPA departed from its historical approach in a significant way in the 2015 Clean Power Plan (CPP) [10] by setting a BSER in which the ''system'' of emissions reduction involved shifting electricity generation from one type of fuel to another. In *West Virginia* v. *EPA,* the Supreme Court applied the major questions doctrine to hold that the term ''system'' did not provide the requisite clear authorization to support the CPP's BSER, which the Court described as ''carbon emissions

[1] 42 U.S.C. 7411(b)(2) provides the EPA the authority to establish subcategories.

[2] *West Virginia* v. *EPA,* 597 U.S. 697, 709 (2022).

[3] 42 U.S.C. 7411(b)(2).

[4] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981); *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999); *Portland Cement Ass'n* v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011); *American Lung Ass'n* v. *EPA,* 985 F.3d 914 (D.C. Cir. 2021), *rev'd in part, West Virginia* v. *EPA,* 597 U.S. 697 (2022). *See also Delaware* v. *EPA,* 785 F.3d 1 (D.C. Cir. 2015).

[5] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433–34 (D.C. Cir. 1973).

[6] *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981). The D.C. Circuit has stated that EPA must also take into account ''technological innovation.'' *See id.* at 347.

[7] *See Lignite Energy Council,* 198 F.3d at 933 (''Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them.'').

[8] See, *e.g.,* Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air pollutants Reviews (77 FR 49494; August 16, 2012) (describing the three-step analysis in setting a standard of performance).

[9] *See West Virginia* v. *EPA,* 597 U.S. at 727 (internal quotations removed).

[10] 80 FR 64662 (Oct. 23, 2015).

caps based on a generation shifting approach'' [11] that capped ''emissions at a level that will force a nationwide transition away from the use of coal to generate electricity[.]'' [12] The Court explained that the EPA's BSER ''forc[es] a shift throughout the power grid from one type of energy source to another,'' which constituted '' 'unprecedented power over American industry' '' and was different in kind from the type of ''system'' of emissions reduction envisioned by CAA section 111(d).[13]

To qualify for selection as the BSER, the system of emission reduction must be ''adequately demonstrated'' as ''the Administrator determines.'' The plain text of CAA section 111(a)(1), and in particular the terms ''adequately'' and ''the Administrator determines,'' confer discretion to the EPA in identifying the appropriate system, including making scientific and technological determinations and considering a broad range of policy considerations.[14] However, the terms ''adequately'' and ''demonstrated,'' as well as applicable caselaw, make clear that the EPA may not determine that a ''purely theoretical or experimental'' system is ''adequately demonstrated.'' [15]

In addition, CAA section 111(a)(1) requires the EPA to account for ''the cost of achieving [the emission] reduction'' in determining the adequately demonstrated BSER. Although the CAA does not describe how the EPA is to account for costs to affected sources, the D.C. Circuit has formulated the cost standard in various ways, including stating that the EPA may not adopt a standard the cost of which would be ''excessive'' or ''unreasonable.'' [16] The EPA has considerable discretion in considering cost under section 111(a), both in determining the appropriate level of costs and in balancing costs with other BSER factors.[17] The D.C. Circuit has repeatedly upheld the EPA's consideration of cost in reviewing standards of performance.[18]

The Agency does not apply a brightline test in determining what level of cost is reasonable. In evaluating whether the cost reasonableness of a particular system of emission reduction, the EPA considers various costs associated with the particular air pollution control measure or a level of control, including capital costs and operating costs, and the emission reductions that the control measure or particular level of control can achieve. The Agency considers these costs in the context of the industry's overall capital expenditures and revenues. The Agency also considers cost effectiveness analysis as a useful metric, and a means of evaluating whether a given control achieves emission reduction at a reasonable cost. A cost effectiveness analysis allows comparisons of relative costs and outcomes (effects) of two or more options. In general, cost effectiveness is a measure of the outcomes produced by resources spent. In the context of air pollution control options, cost effectiveness typically refers to the annualized cost of implementing an air pollution control option divided by the amount of pollutant reductions realized annually. Notably, a cost effectiveness analysis is not intended to constitute or approximate a benefit-cost analysis in which benefits are compared to costs but rather is intended to provide a metric to compare the relative cost of different air pollution control options. The EPA typically has considered cost effectiveness along with various associated cost metrics, such as capital costs and operating costs, total costs, costs as a percentage of capital for a new facility, and the cost per unit of production. In many contexts, the cost per unit of production may be passed on to consumers, including ratepayers in the utility context and consumers of end products in other contexts.

Under CAA section 111(a)(1), the EPA is required to take into account ''any nonair quality health and environmental impact and energy requirements'' in determining the BSER. Nonair quality health and environmental impacts may include the impacts of the disposal of byproducts of the air pollution controls, or requirements of the air pollution control equipment for water.[19] Energy requirements may include the impact, if any, of the air pollution controls on the source's own energy needs.[20] In addition, based on the D.C. Circuit's interpretations of CAA section 111, energy requirements may also include the impact, if any, of the air pollution controls on the energy supply for a particular area or nationwide.[21] In addition, the EPA has considered under this statutory factor whether possible controls would create risks to the reliability of the electricity system.

After the EPA evaluates the statutory factors with respect to adequately demonstrated control technologies, the EPA compares the various systems of emission reductions and determines which system is ''best,'' and therefore represents the BSER. The D.C. Circuit has also held that the term ''best'' authorizes the EPA to consider factors in addition to the ones enumerated in CAA section 111(a)(1) that further the purpose of the statute. In particular, consistent with the plain language and the purpose of CAA section 111(a)(1), which requires the EPA to determine the ''best system of *emission reduction*'' (emphasis added), the EPA must consider the quantity of emissions at issue.[22] In determining which adequately demonstrated system of emission reduction is the ''best,'' the EPA has broad discretion. In *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981), the court explained that ''section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS'' [23] and emphasized that ''[t]he text gives the EPA broad discretion to weigh different factors in setting the standard,'' including the amount of emission reductions, the cost of the controls, and the non-air quality environmental impacts and energy requirements.[24]

The EPA then establishes a standard of performance that reflects the degree of emission limitation achievable through the implementation of the BSER. A standard of performance is

[11] *West Virginia* v. *EPA,* 597 U.S. at 732.

[12] *Id.* at 734.

[13] *Id.* at 728 (citation omitted).

[14] *Nat'l Asphalt Pavement Ass'n* v. *Train,* 539 F.2d 775, 786 (D.C. Cir. 1976); *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 434 (D.C. Cir. 1973).

[15] *Essex Chem. Corp.,* 486 F.2d at 433–34; *see Portland Cement Assn.* v. *Ruckelshaus,* 486 F.2d 375, 391–92 (D.C. Cir. 1973) (EPA may not base an ''adequately demonstrated'' determination on a '' 'crystal ball' inquiry'') (citation omitted).

[16] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981). *See* 79 FR 1430, 1464 (January 8, 2014); *Lignite Energy Council,* 198 F.3d at 933 (costs may not be ''exorbitant''); *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975) (costs may not be ''greater than the industry could bear and survive'').

[17] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981).

[18] *See Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 440 (D.C. Cir. 1973); *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 387–88 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298, 313 (D.C. Cir. 1981).

[19] *Portland Cement Ass'n* v. *Ruckelshaus,* 465 F.2d 375, 387–88 (D.C. Cir. 1973), *cert. denied,* 417 U.S. 921 (1974).

[20] For details on the modeled energy requirements associated with CCS, please see section 6.4 of the RIA for this rule.

[21] *See Sierra Club* v. *Costle,* 657 F.2d at 327–28 (quoting 44 FR 33583–84; June 11, 1979); 79 FR 1430, 1465 (January 8, 2014) (citing *Sierra Club* v. *Costle,* 657 F.2d at 351).

[22] *Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981). The D.C. Circuit has also held that Congress intended for CAA section 111 to create incentives for new technology and therefore that the EPA is required to consider technological innovation as one of the factors in determining the ''best system of emission reduction.'' *See id.* at 346–47.

[23] *Sierra Club* v. *Costle,* 657 F.2d at 319; *see also AEP* v. *Connecticut,* 564 U.S. 410, 427 (2011).

[24] *Sierra Club* v. *Costle,* 657 F.2d at 321; *see also New York* v. *Reilly,* 969 F.2d at 1150.

''achievable'' if a technology can reasonably be projected to be available to an individual source at the time it is constructed so as to allow it to meet the standard.[25] For purposes of evaluating the source category and determining BSER, the EPA can determine whether subcategorization is appropriate based on classes, types, and sizes of sources, and may identify a different BSER and establish different performance standards for each subcategory. The result of the analysis and BSER determination leads to standards of performance that apply to facilities that begin construction, reconstruction, or modification after the date of publication of the proposed standards in the **Federal Register**. Because the NSPS reflect the BSER under conditions of proper operation and maintenance, in doing its review, the EPA also evaluates and determines the proper testing, monitoring, recordkeeping and reporting requirements needed to ensure compliance with the emission standards.

### *B. How does the EPA perform the NSPS review?*

CAA section 111(b)(1)(B) requires the EPA to, ''at least every 8 years, review and, if appropriate, revise'' the standards of performance applicable to new, modified, or reconstructed sources. However, the Administrator need not review any such standard if the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. If the EPA revises the standards of performance, they must reflect the degree of emission limitation achievable through the application of the BSER, which is selected from among adequately demonstrated technologies after consideration of the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements.[26] When conducting a review of an existing performance standard, the EPA may, as appropriate and consistent with the statutory requirements, add emission limits for pollutants or emission sources not currently regulated for that source category.

In reviewing an NSPS for a source category to determine whether it is ''appropriate'' to revise the standards of performance, the EPA evaluates the statutory factors, which may include consideration of the following information:[27]

- Expected growth for the source category, including how many new facilities, modifications, or reconstructions may trigger NSPS in the future.
- Pollution control measures, including advances in control technologies, process operations, design or efficiency improvements, or other systems of emission reduction, that the Administrator determines have been ''adequately demonstrated'' in the regulated industry.
- Available information from the implementation and enforcement of current requirements indicating that emission limitations and percent reductions beyond those required by the current standards are achieved in practice.
- Costs (including capital and annual costs) associated with implementation of the available pollution control measures.
- The amount of emission reductions achievable through application of such pollution control measures.
- Any non-air quality health and environmental impact and energy requirements associated with those control measures.

### *C. What is the source category regulated in this final action?*

The EPA first promulgated NSPS for stationary gas turbines on September 10, 1979.[28] These standards of performance are codified in 40 CFR part 60, subpart GG, and are applicable to sources that commenced construction, modification, or reconstruction after October 3, 1977. The standards of performance in subpart GG regulate emissions of $NO_X$ and $SO_2$ from all new, modified, or reconstructed simple and regenerative cycle gas turbines and the gas turbine portion of a combined cycle steam/electric generating system. The EPA last reviewed and revised the $NO_X$ and $SO_2$ standards of performance on July 6, 2006, and promulgated 40 CFR part 60, subpart KKKK, which is applicable to stationary combustion turbines that commenced construction, modification, or reconstruction after February 18, 2005.[29] In subpart KKKK, the definition of the source was expanded to include all equipment, including but not limited to the combustion turbine; the fuel, air, lubrication, and exhaust gas systems; the control systems (except emission control equipment); the heat recovery system (including heat recovery steam generators (HRSG) and duct burners); and any ancillary components and sub-components comprising any simple cycle, regenerative/recuperative cycle, and combined cycle stationary combustion turbine, and any combined heat and power (CHP) stationary combustion turbine-based system.

The stationary combustion turbine source category consists of combustion turbines with design base load ratings (*i.e.,* maximum heat input at ISO conditions) equal to or greater than 10.7 gigajoules per hour (GJ/h) (10 million British thermal units per hour (MMBtu/h))[30] based on the higher heating value (HHV) of the fuel and applies to combustion turbines and their associated HRSG and duct burners, as described above. The source is ''stationary'' because the combustion turbine is not self-propelled or intended to be propelled while performing its function. Combustion turbines may, however, be mounted on a vehicle (or trailer) for portability and still be considered stationary. As discussed in section IV.B.2.e of this preamble, the EPA is amending the applicability of subparts KKKK and KKKKa to provide that combustion turbines that are subject to applicable CAA title II standards are not subject to the NSPS. To the EPA's knowledge, no such stationary combustion turbines are currently being used in temporary applications.

The $NO_X$ standards in subparts GG and KKKK are generally based on the application of combustion controls (as the BSER) and allow the turbine owner or operator the choice of meeting a concentration-based emission standard or an output-based emission standard. The concentration-based emission limits are in units of parts per million by volume dry (ppmvd) at 15 percent oxygen gas ($O_2$).[31] The output-based emission limits are in units of mass per unit of useful recovered energy, nanograms per joule (ng/J) or pounds per megawatt-hour (lb/MWh). Each $NO_X$ limit in subparts GG and KKKK is based on the application of combustion controls as the BSER, but individual standards may differ for individual

[25] *Sierra Club* v. *Costle,* 657 F.2d at 364, n.276.

[26] *See* 42 U.S.C. 7411(a)(1).

[27] *See generally* 42 U.S.C. 7411; 76 FR 65653, 65658 (Oct. 24, 2011).

[28] *See* 44 FR 52792 (Sept. 10, 1979).

[29] *See* 71 FR 38482 (July 6, 2006).

[30] The base load rating is based on the heat input to the combustion turbine engine. Any additional heat input from duct burners used with 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 HRSG and duct burners that are associated with a combustion turbine subject to this subpart.

[31] Throughout this document, all references to parts per million (ppm) $NO_X$ are intended to be interpreted as ppmvd at 15 percent $O_2$, unless otherwise noted.

subcategories of combustion turbines based on the following factors: the fuel input rating at base load, the fuel used, the application, the load, and the location of the turbine.[32] The fuel input rating of the turbine does not include any supplemental fuel input to the heat recovery system and refers to the rating of the combustion turbine itself.

The standards of performance for $SO_2$ emissions in subparts GG and KKKK reflect the BSER of using low-sulfur fuels for all new, modified, or reconstructed combustion turbines, regardless of class, size, or type. The input-based $SO_2$ standard applies to the sulfur content of the fuel combusted in the turbine. The NSPS also includes an optional output-based standard that limits the discharge of excess $SO_2$ into the atmosphere as a fraction of the gross energy output of the combustion turbine.[33]

Combustion turbines are a large and diverse source category. Thousands of stationary combustion turbines are operating across numerous industrial sectors. For instance, in the utility sector alone, there are approximately 3,400 existing stationary combustion turbines.[34] Generally, existing combustion turbine sources are subject to either subpart KKKK or subpart GG.

The EPA last revised the NSPS for stationary combustion turbines in 2006, when it promulgated subpart KKKK. In 2022, certain parties filed a complaint in Federal district court pursuant to CAA section 304 alleging that the EPA had failed to fulfill a nondiscretionary duty under CAA section 111(b)(1)(B) to review and, if appropriate, revise this NSPS within 8 years of the 2006 revision. The EPA resolved this litigation through entering a consent decree establishing judicially enforceable deadlines for the EPA to propose and finalize this NSPS review.[35] The EPA is discharging its obligations under the consent decree in this final rule.

The EPA proposed the current review of the stationary combustion turbines NSPS on December 13, 2024. We received 167 unique comments from private citizens, environmental and public health advocacy groups, community organizations, Tribes, and States. The EPA also received unique comments from numerous industrial sectors, including electric utilities, public power cooperatives, original equipment manufacturers (OEMs), trade groups and associations, and certain sectors of the oil and gas industry. In addition, thousands of similar comments were submitted by individuals as part of mass mailer campaigns. A summary of significant comments we timely received regarding the 2024 Proposed Rule and our responses are provided in this preamble. A summary of all other public comments on the proposal and the EPA's responses to those comments is available in the *Summary of Public Comments and Responses: Review of New Source Performance Standards for Stationary Combustion Turbines and Stationary Gas Turbines,* Docket ID No. EPA–HQ–OAR–2024–0419. In this action, the EPA is finalizing decisions and revisions pursuant to its CAA section 111(b)(1)(B) review of the NSPS for stationary combustion turbines and stationary gas turbines that reflect our consideration of all the comments received.

### *D. The Role of the NSPS*

The role of NSPS in relation to other requirements of the Act is to establish a minimum Federal baseline for pollution control performance that all new, modified, or reconstructed facilities within a specific source category must meet. While independently established by the EPA and based strictly on the statutory criteria, in practice, NSPS often act as a starting point for permitting requirements, such as emission limits and standards that may be established through other programs *(e.g.,* the New Source Review (NSR) permitting program or State and local requirements). NSPS are directly enforceable against sources.[36] However, effective implementation is often achieved through collaboration with State and local authorities, who may have delegated authority to implement NSPS and who are typically responsible for incorporating NSPS requirements into operating permits.

Permitting decisions may result in more stringent emissions standards for individual sources than the NSPS based on different legal requirements and case-by-case assessments of the appropriate requirements for individual facilities considering source-specific information, such as the local air quality conditions.[37] For example, a permitting authority evaluating permit requirements for a new combustion turbine in an area that has been designated as non-attainment for ozone under the National Ambient Air Quality Standards (NAAQS) program must set a standard based on the ''lowest achievable emissions rate'' (LAER) (and also must offset new emissions with reductions from other sources).[38] Under a LAER analysis, a $NO_X$ emissions standard lower than what is required in this final rule may be appropriate (*e.g.,* an emissions standard of less than 5 ppm $NO_X$ based on the application of SCR). That decision does not necessarily mean the same level of emissions performance must be required for all combustion turbines in the country through the NSPS. The reverse is also true—it is not necessarily appropriate to use the emission standards in an NSPS as the sole justification for not requiring additional emissions reduction measures under facility-specific permitting authorities.

## III. What changes did we propose for the stationary combustion turbines and stationary gas turbines NSPS?

On December 13, 2024, the EPA proposed the current review of, and several revisions to, the stationary combustion turbines and stationary gas turbines NSPS. In that action, we proposed to establish size-based subcategories for new, modified, or reconstructed stationary combustion turbines in 40 CFR part 60, subpart KKKKa that also recognized distinctions between those sources that operate at varying loads or capacity factors, those firing natural gas or non-natural gas fuels, and those that operate in unique locations. Capacity factor or ''utilization'' level or rate is a ratio that measures how often a stationary combustion turbine is operating at its maximum rated heat input. The ratio is based on heat input, or *actual* heat input, compared to the base load rating, or *potential* maximum heat input, under specified conditions.

The EPA proposed post-combustion SCR in addition to combustion controls to be the BSER for limiting $NO_X$ emissions from certain combustion turbines in the small, medium, and large size-based subcategories. The EPA proposed SCR to be adequately demonstrated and generally cost-effective for combustion turbines in this

[32] Throughout this document, all uses of the term ''turbine'' refer to a ''combustion turbine'' as defined in subparts KKKK and KKKKa.

[33] See the 2024 Proposed Rule (89 FR 101310; Dec. 13, 2024) for further discussion of the specific subcategories in previous NSPS and the applicable limits for $NO_X$ and $SO_2$ emissions in those rules.

[34] *See* the U.S. Environmental Protection Agency's (EPA) National Electric Energy Data System database. NEEDS rev 06–06–2024. Accessed at *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs.*

[35] *See* Consent Decree, *Environmental Defense Fund et al.* v. *EPA,* No. 3:22–cv–07731–WHO (N.D. Cal. July 27, 2023).

[36] *See* 42 U.S.C. 7411(e).

[37] Experience with emissions control technologies gained through permitting for specific projects can often help inform the EPA when conducting its periodic reviews of the NSPS.

[38] 42 U.S.C. 7503.

source category when those turbines are operated at higher utilization rates. The EPA also proposed that a BSER that includes SCR satisfies the other statutory criteria under CAA section 111(a)(1). We sought comment on these proposed determinations, including on the issues set forth below.

However, the EPA recognized that as the size of a combustion turbine diminishes and/or as the level of operation (*i.e.,* utilization on an annual basis) of a combustion turbine diminishes or becomes more variable, the incremental cost-effectiveness on a per-ton basis and efficacy of SCR technology also diminishes. Thus, at smaller sizes and at lower rates of utilization, we proposed to establish standards of performance based on a BSER of combustion controls without SCR. Specifically, for small combustion turbines (*i.e.,* at proposal, those that have a base load heat input rating less than or equal to 250 MMBtu/h) that operate at an annual capacity factor less than or equal to 40 percent (*i.e.,* at proposal, ''low'' and ''intermediate'' utilization combustion turbines), we proposed that the use of combustion controls alone remains the BSER. For medium combustion turbines (*i.e.,* at proposal, those that have a base load heat input rating greater than 250 MMBtu/h and less than or equal to 850 MMBtu/h) that operate at capacity factors less than or equal to 20 percent (*i.e.,* low-utilization combustion turbines), we proposed that combustion controls alone remain the BSER. Likewise, for large combustion turbines (*i.e.,* those that have a base load heat input rating greater than 850 MMBtu/h) that operate at capacity factors less than or equal to 20 percent (*i.e.,* low-utilization combustion turbines), we proposed that combustion controls alone remain the BSER.

Based on the application of these $NO_X$ control technologies, the EPA proposed to lower the $NO_X$ standards of performance for most of the stationary combustion turbines in this source category relative to subpart KKKK. In addition, the EPA proposed to maintain the current standards for $SO_2$ emissions after finding that the use of low-sulfur fuels remains the BSER.

The Agency also proposed amendments or requested comment to address several technical and editorial issues that had arisen under the existing regulations in subparts GG and KKKK, which also could be relevant to the new subpart KKKKa. These included, among other things, whether to revise the definition of ''reconstruction'' for this source category; how to address unique challenges faced by newer higher efficiency combustion turbines in meeting the current subpart KKKK standard of performance of 15 ppm $NO_X$ for large turbines; whether to include alternative, optional mass-based $NO_X$ standards of performance; whether to adjust the current approach to the part-load $NO_X$ standards; whether to provide a process for site-specific $NO_X$ standards of performance when burning byproduct fuels; how to address co-firing of non-natural gas fuels, including hydrogen; whether and how to handle certain kinds of emergency operations; whether to include an exemption from title V permitting for non-major sources under CAA section 502(a); whether to address other criteria air pollutants; and whether to create a subcategory or exemption for combustion turbines used in temporary applications, such as for less than 1 year, similar to current NSPS and national emission standards for hazardous air pollutants (NESHAP) provisions for internal combustion engines and industrial boilers.[39]

### IV. What actions are we finalizing and what is our rationale for such decisions?

The EPA is finalizing revisions to the NSPS for stationary combustion turbines and stationary gas turbines pursuant to its CAA section 111(b)(1)(B) review. The EPA is promulgating the NSPS revisions in a new subpart, 40 CFR part 60, subpart KKKKa. The revised NSPS subpart is applicable to affected sources constructed, modified, or reconstructed after December 13, 2024. A complete list of the final subcategories and associated emissions standards being finalized in this action is provided in Table 1 in section IV.B.5 of this preamble.

After considering comments critical of the proposed size-based subcategory threshold between small and medium combustion turbines, the EPA has decided to retain in subpart KKKKa the general size-based subcategories from subpart KKKK. This includes subcategories for new, modified, or reconstructed stationary combustion turbines with base load ratings greater than 850 MMBtu/h of heat input (*i.e.,* large), base load ratings greater than 50 MMBtu/h and less than or equal to 850 MMBtu/h of heat input (*i.e.,* medium), and base load ratings less than or equal to 50 MMBtu/h of heat input (*i.e.,* small). In addition, certain subcategories of new stationary combustion turbines in subpart KKKKa reflect the correlation between the level of utilization of a combustion turbine and the cost effectiveness of available control technologies in limiting $NO_X$ emissions. This correlation was discussed in the proposed rule and generated significant input in public comments.[40] The final rule therefore subcategorizes large and medium combustion turbines according to how they are operated—either at high rates of utilization or low rates of utilization. A new large or medium combustion turbine with a 12-calendar-month capacity factor greater than 45 percent is subcategorized as a high-utilization source. A new large or medium combustion turbine with a 12-calendar-month capacity factor less than or equal to 45 percent is subcategorized as a low-utilization source. Small combustion turbines are not being further subcategorized based on utilization.

In addition, taking into consideration public comments in response to the EPA's discussion in the proposal of the unique challenges faced by new large higher efficiency combustion turbines, we are finalizing two subcategories for large low-utilization turbines based on the design efficiency of the turbine, which accounts for different levels of emissions performance that can be achieved by combustion controls alone (*i.e.,* without SCR).[41] Specifically, for new large turbines with low rates of utilization (*i.e.,* a 12-calendar-month capacity factor less than or equal to 45 percent) and design efficiencies greater than or equal to 38 percent on a HHV basis, the EPA is finalizing a determination that the BSER is the use of combustion controls alone.[42] For new large turbines with low rates of utilization (*i.e.,* a 12-calendar-month capacity factor less than or equal to 45 percent) and design efficiencies less than 38 percent, the EPA is finalizing a

[39] See the proposed rule preamble for additional discussion about these and other proposals and requests for comment (89 FR 101306; Dec. 13, 2024). See section IV of this preamble for discussion of the proposals being finalized in subpart KKKKa and section VI of this preamble for discussion of the proposals not being finalized in this action.

[40] The proposal differentiated the cost effectiveness of combustion controls and SCR for combustion turbines operating at low, intermediate, and base load levels. *See* 89 FR 101315.

[41] Efficiency for purposes of subcategorization in 40 CFR part 60, subpart KKKKa refers to the design efficiency of a specific class or type of stationary combustion turbine according to manufacturer specifications. Turbine manufacturers list this value as a percentage based on the HHV of the individual turbine design.

[42] The 38 percent HHV design efficiency is equal to 42 percent on a lower heating value (LHV) basis. In relation to the design efficiency rating of a combustion turbine, ratings based on the HHV will appear lower, as the calculation includes a portion of heat that may not be recoverable in many applications. Efficiency ratings based on the LHV will appear higher because they exclude the energy lost with the water vapor in the exhaust.

determination that the BSER is the use of combustion controls with $NO_X$ emissions rate guarantees based on the use of technologies such as lean premix combustion and dry low-$NO_X$ (DLN) or ultra DLN burners.[43]

The EPA is finalizing a determination that the BSER is the use of various types of combustion controls (*i.e.,* without SCR) for all but one subcategory of new, modified, or reconstructed stationary combustion turbines. For that one subcategory—new large turbines with high rates of utilization (*i.e.,* 12-calendar-month capacity factors greater than 45 percent)—the BSER is combustion controls with SCR.

The standards of performance for each subcategory of stationary combustion turbine in subpart KKKKa reflect the degree of emission limitation achievable based upon application of the BSER. For new large high-utilization turbines firing natural gas with a BSER of combustion controls with SCR, the $NO_X$ standard is 5 ppm. For new large natural gas-fired turbines with low rates of utilization, the $NO_X$ standard is 25 ppm for higher efficiency classes of turbines and 9 ppm for lower efficiency classes.

For new medium high-utilization combustion turbines firing natural gas, the $NO_X$ standard is 15 ppm based on the performance of dry combustion controls. For new medium low-utilization turbines firing natural gas, the $NO_X$ standard is 25 ppm based on the performance of water- or steam-injection combustion controls. The high/low utilization threshold—greater than or less than or equal to a 45 percent capacity factor—is the same for new medium combustion turbines as for new large combustion turbines. And for all new small combustion turbines firing natural gas, the $NO_X$ standard is 25 ppm based on combustion controls regardless of the level of utilization.[44]

This action maintains subcategories for modified and reconstructed stationary combustion turbines that are generally consistent with the subcategories in subpart KKKK. As discussed in section IV.B.6, these subcategories are based on a BSER of combustion controls with associated $NO_X$ standards of performance. As discussed in section VI.A of this preamble, the EPA is not finalizing the proposed, category-specific definition of ''reconstruction'' for combustion turbines.

Some of the other final determinations reflected in subpart KKKKa include: the creation of a new subcategory for stationary temporary combustion turbines; lowering the threshold that defines part-load operations to any hour when the heat input of the combustion turbine is less than or equal to 70 percent of the base load rating; allowing owners or operators to petition the Administrator for a site-specific $NO_X$ standard when burning byproduct fuels; a provision that operation during a ''system emergency'' (Energy Emergency Alert levels 1, 2, or 3) is not included in calculating a turbine's 12-calendar-month utilization; an exemption from title V permitting for combustion turbines that are not major sources or located at major sources under CAA section 502(a); and retention of the $SO_2$ standards from subpart KKKK for all new, modified, or reconstructed stationary combustion turbines.[45][46]

The EPA is finalizing corresponding amendments in subparts GG and KKKK with respect to several of these ancillary issues, which will be applicable to combustion turbines subject to those subparts as of the effective date of this final rule. Specifically:

- In subpart GG, the EPA is finalizing that turbines subject to subparts Da, KKKK, or KKKKa are not subject to subpart GG.
- In subpart KKKK, the EPA is finalizing a clarification that only the heat input to the combustion turbine engine is used for applicability purposes and that combustion turbines regulated under subpart KKKK are exempt from subparts KKKKa and GG. The EPA is also finalizing that emergency, military, and firefighting combustion turbines are exempt from the $NO_X$ emission standards in subpart KKKK. Additionally, the EPA is finalizing flexibilities regarding when performance tests must be conducted after long periods of non-operation and that owners or operators can use fuel records to comply with their $SO_2$ standard. The EPA is finalizing a low-Btu alternative to the $SO_2$ standard in subpart KKKK, as well as a concentration-based alternate $SO_2$ standard. Finally, the EPA is finalizing the requirement for approval from the delegated authority for certain monitoring and compliance tasks that are already covered under 40 CFR part 75 and specifications about including duct burners in performance tests.
- In both subparts GG and KKKK, the EPA is finalizing that as an alternative to being subject to either of those subparts, owners or operators of combustion turbines that otherwise meet those subparts' applicability criteria may petition the Administrator to become subject to subpart KKKKa instead. The EPA is also finalizing in both subparts GG and KKKK that turbines subject to subparts J or Ja are not subject to the respective $SO_2$ standard in subparts GG or KKKK and that $NO_X$ continuous emissions monitoring systems (CEMS) installed and certified according to 40 CFR part 75 can be used to monitor $NO_X$ emissions, where approved. The EPA is finalizing standard electronic reporting requirements for turbines subject to subparts GG or KKKK and that an additional test method (EPA Method 320) can be used to determine $NO_X$ and diluent concentration in subparts GG and KKKK.

It is the EPA's understanding and intention that none of these changes alter the stringency or increase any regulatory burdens with respect to the existing combustion turbines subject to subparts GG and KKKK, and nothing in this final rule is intended to have retroactive effect (that is, to govern any conduct or activities occurring prior to the effective date of this final rule).

This action finalizes standards of performance in subpart KKKKa that apply at all times, including during periods of startup, shutdown, and malfunction (SSM), and other changes such as electronic reporting that also apply to previous NSPS subparts GG and KKKK. These topics are discussed below in sections IV.F–H.

### A. Applicability

The source category that is the subject of this final action is composed of new, modified, or reconstructed stationary combustion turbines with a base load rating of greater than 10 MMBtu/h of heat input.[47] The standards of

[43] Dry combustion controls that include the use of lean premix, DLN, ultra DLN, and other technologies are often referred to as ''advanced'' combustion controls by turbine manufacturers and the regulated community. These technologies are generally more effective at $NO_X$ control than other dry combustion controls but are not available for all types, sizes, and applications of new, modified, or reconstructed stationary combustion turbines. The EPA uses the same terminology in this preamble to make the same distinction.

[44] *See* Table 1 of this preamble for a complete listing of subcategories and associated $NO_X$ emissions standards.

[45] Energy Emergency Alert levels 1, 2, and 3 are defined by the North American Electric Reliability Corporation (NERC) Reliability Standard EOP–011–2, or its successor, or equivalent.

[46] *See* section IV.B.7.d of this preamble for discussion of site-specific $NO_X$ standards for stationary combustion turbines in subpart KKKKa. *See* sections IV.B.3–4 for discussion of the BSER for the different subcategories of stationary combustion turbines. *See* section IV.B.5 for discussion of the associated $NO_X$ standards based on the application of the BSER.

[47] The base load rating is the maximum heat input of the combustion turbine engine at ISO conditions. The EPA uses the HHV when specifying heat input ratings.

performance, codified in 40 CFR part 60, subpart KKKKa, are directly applicable to affected sources that began construction, modification, or reconstruction after December 13, 2024—the date of publication of the proposed standards in the **Federal Register**. The final amendments to subparts GG and KKKK are directly applicable to the affected facilities already subject to those subparts. Stationary combustion turbines subject to the standards in subpart KKKKa are not subject to the requirements of subparts GG or KKKK. The HRSG and duct burners subject to the standards in subpart KKKKa are exempt from the requirements of 40 CFR part 60, subpart Da (the Utility Boiler NSPS) as well as subparts Db and Dc (the Industrial/Commercial/Institutional Boiler NSPS), continuing the approach previously established in subpart KKKK.

Subpart KKKKa maintains certain exemptions from $NO_X$ emissions standards promulgated previously in subparts GG and KKKK. In 1977, in subpart GG, the EPA determined that it was appropriate to exempt emergency combustion turbines from the $NO_X$ limits. These included emergency-standby combustion turbines, military combustion turbines, and firefighting combustion turbines. Subpart KKKK further defined emergency combustion turbines as units that operate in emergency situations, such as turbines that supply electric power when the local utility service is interrupted. Additional exemptions being maintained from subpart KKKK include: (1) stationary combustion turbine test cells/stands, (2) integrated gasification combined cycle (IGCC) combustion turbine facilities covered by subpart Da of 40 CFR part 60 (the Utility Boiler NSPS), and (3) stationary combustion turbines that, as determined by the Administrator or delegated authority, are used exclusively for the research and development of control techniques and/or efficiency improvements relevant to stationary combustion turbine emissions.

In general, and as discussed in the following sections, the EPA is finalizing minor changes in wording and writing style to add clarity to the applicability language in subparts GG and KKKK and to track with language being finalized in subpart KKKKa. The Agency does not intend for these editorial revisions to applicability and/or updates to the test methods to substantively change any of the technical requirements of existing subparts GG and KKKK.

1. Exemptions for Combustion Turbines Subject to More Stringent Standards

The EPA is finalizing as proposed provisions to make clear that stationary combustion turbines at petroleum refineries subject to 40 CFR part 60, subparts J or Ja are not subject to the $SO_2$ performance standards in subparts GG, KKKK, or KKKKa. The $SO_2$ standards in subparts J and Ja are more stringent than the $SO_2$ limits in subparts GG, KKKK, or KKKKa. This clarification simplifies compliance for owners or operators of petroleum refineries without an increase in pollutant emissions by minimizing overlap of competing NSPS for different source categories. The EPA received supportive and no adverse comments on the subpart J and Ja related amendments. The EPA is unaware of additional source categories or facilities with stationary combustion turbines that are subject to more stringent NSPS that should not be subject to the $SO_2$ and/or $NO_X$ performance standards in subparts GG, KKKK, or KKKKa. Further, no commenters identified any such categories or facilities.

2. Petition To Comply With 40 CFR Part 60, Subpart KKKKa

The EPA is finalizing as proposed a provision that will allow owners or operators of stationary combustion turbines currently covered by subparts GG or KKKK, and any associated steam generating unit subject to an NSPS, to petition the Administrator to comply with subpart KKKKa in lieu of complying with subparts GG, KKKK, and any associated steam generating unit NSPS. Since the applicability of subpart KKKKa encompasses any associated heat recovery equipment, owners or operators can have the flexibility to comply with one NSPS instead of multiple NSPS. The Administrator will only grant the petition if it is determined that compliance with subpart KKKKa would be equivalent to, or more stringent than, compliance with subparts GG, KKKK, or any associated steam generating unit NSPS.

Also, if any solid fuel as defined in subpart KKKKa is burned in the HRSG, the HRSG is covered by the applicable steam generating unit NSPS and not subpart KKKKa. The intent of the solid fuel exclusion in subpart KKKKa is that it is only applicable to new turbines burning liquid and gaseous fuels. The exclusion prevents a large solid fuel-fired boiler from using the exhaust from a combustion turbine engine to avoid the requirements of the applicable steam generating unit NSPS.

*B. $NO_X$ Emissions Standards*

1. Overview

This section discusses the EPA's final BSER determinations for $NO_X$ emissions for each of the subcategories of new, modified, or reconstructed stationary combustion turbines and the associated standards of performance. The EPA explains in section IV.B.2 of this preamble the subcategory approach it is adopting in subpart KKKKa. Sections IV.B.3 and IV.B.4 of this preamble present the EPA's BSER analysis of the $NO_X$ control technologies the EPA evaluated as part of this review of the NSPS, which include dry combustion controls, wet combustion controls (*e.g.,* water or steam injection), and post-combustion SCR. Dry combustion controls include ''advanced'' systems that incorporate lean premix with dry low-$NO_X$ (DLN) or ultra DLN burners to reduce the flame temperature and further limit $NO_X$ formation. In section IV.B.5 of this preamble, the EPA sets out the final $NO_X$ performance standards, based on the application of a particular BSER for each subcategory of stationary combustion turbine.

In determining the subcategories, BSER, and $NO_X$ standards in this action, the EPA considered multiple characteristics of combustion turbines within the source category. These included whether the size of a new, modified, or reconstructed stationary combustion turbine is small, medium, or large; whether the affected source is of a type that typically operates at high or low annual capacity factors (*i.e.,* utilization); whether certain affected sources are higher or lower efficiency designs; whether the affected source operates at full load or part load; and whether the affected source burns natural gas, non-natural gas (such as gaseous hydrogen or liquid distillate), or a combination of fuels.

In section IV.B.6 of this preamble, the EPA explains the final BSER determinations and $NO_X$ emission standards for modified and reconstructed sources. The EPA is finalizing $NO_X$ emission standards for modified and reconstructed stationary combustion turbines that are different than those for new sources and reflect the EPA's determination that combustion controls without SCR are the BSER for these sources. This approach reflects comments that explained that many existing turbines undergoing modification or reconstruction face unique, site-specific challenges to retrofitting SCR, which can dramatically increase costs.

Furthermore, in sections IV.B.2.d and IV.B.7.b of this preamble, the EPA discusses the $NO_X$ control technologies that the EPA has determined to be the BSER for each of the non-natural gas subcategories and also explains its approach to characterizing new, modified, or reconstructed stationary combustion turbines that elect to co-fire with hydrogen as either natural gas-fired or non-natural gas-fired. Specifically, combustion turbines that elect to co-fire with natural gas blended with hydrogen are subject to the same BSER and $NO_X$ performance standards as those applicable to either natural gas-fired or non-natural gas-fired combustion turbines, depending on the size- and utilization-based subcategory. Section IV.B.2.e of this preamble includes discussion of the new subcategory for stationary combustion turbines used in temporary applications.

2. Subcategorization

This section describes the subcategorization approach being finalized in subpart KKKKa. The discussion that follows begins with a summary of the subcategories in the proposed rule and concludes with a discussion of the final subcategory determinations and the Agency's rationale in support of those decisions. As noted in the proposal, the EPA bases subcategories on the characteristics of combustion turbines that are relevant to the reasonableness of potential BSER controls (*i.e.,* characteristics that make potential controls reasonable or unreasonable in accordance with one or more of the BSER factors in CAA section 111(a)(1)). Therefore, the availability and performance of $NO_X$ controls for different designs, sizes, *etc.,* of stationary combustion turbines have informed the Agency's subcategorization decisions.

To this end, this section discusses the characteristics of various combustion turbines—such as their size, utilization level, and efficiency—and why these characteristics are appropriate bases for subcategorization of sources, as well as how they impact the determinations of the BSER and associated $NO_X$ standards of performance.[48] Summaries of significant comments received during the public comment period and the EPA's responses to those comments are included in the appropriate sections below. The EPA's further response to comments on the proposal, including any comments not discussed in this preamble, can be found in the EPA's response to comments document in the docket for this rule.[49] [50]

a. Subcategorization Based on Size

At proposal, the EPA continued the approach from subpart KKKK of determining subcategories based on combustion turbine size, as reflected by the base load rated heat input of an individual combustion turbine.[51] As discussed in the proposal, the size of a combustion turbine is related to its intended application, whether industrial or utility, and the combination of those factors influences the availability and performance of $NO_X$ combustion controls, making it a relevant consideration for subcategorization and subsequent BSER determinations.[52] The EPA proposed to maintain some of the size cutoffs for defining subcategories from subpart KKKK and proposed to revise others.

The proposed subcategory of large combustion turbines included new, modified, or reconstructed sources with base load ratings greater than 850 MMBtu/h of heat input. This subcategory of large turbines maintained the size-based threshold from subpart KKKK. However, the proposed size-based thresholds for medium and small combustion turbines were revised relative to subpart KKKK. The EPA proposed that the size-based subcategory for medium combustion turbines included new, modified, or reconstructed sources with base load ratings greater than 250 MMBtu/h of heat input and less than or equal to 850 MMBtu/h. The EPA proposed that the size-based subcategory for small combustion turbines included new, modified, or reconstructed sources with base load ratings less than or equal to 250 MMBtu/h of heat input. In addition, for the subcategories of medium and small combustion turbines, the EPA proposed to include both new and reconstructed units in the same size subcategory; and the EPA proposed to determine the same BSER and $NO_X$ emission standards for both new and reconstructed units. This was also in contrast to subcategorizations in subpart KKKK.

In particular, the proposed subcategorization approach for small stationary combustion turbines represented a significant shift from that in subpart KKKK. The EPA proposed that a separate subcategory of combustion turbines smaller than 50 MMBtu/h of heat input is not necessary because multiple turbine manufacturers have developed dry combustion controls capable of limiting $NO_X$ emissions to the same rates as those achieved by larger combustion turbines (*e.g.,* those up to 250 MMBtu/h of heat input) for both electrical and mechanical drive applications. This same rationale also led the EPA to propose that separate subcategories for new small combustion turbines, based on whether they serve electrical or mechanical drive applications, are no longer necessary.

The EPA received significant comments on the size-based subcategorization approach for large, medium, and small stationary combustion turbines.

Many commenters opposed the proposed elimination of the 50 MMBtu/h threshold that distinguishes between the small and medium size subcategories of combustion turbines in the previous NSPS (subpart KKKK). Specifically, the commenters stated that the elimination of the subcategory for very small combustion turbines impacted the EPA's proposed determination of the BSER and associated standards of performance, which they argued were not appropriate for the smallest turbines, *i.e.,* those less than 50 MMBtu/h of heat input. Separately, commenters asserted that the proposed 250 MMBtu/h size threshold did not meaningfully correspond with the emissions performance or other characteristics of models of combustion turbines currently on the market. For example, commenters from the natural gas pipeline industry indicated that they use industrial turbines in sizes of up to 320 MMBtu/h at compressor stations and advocated that the small size subcategory should be increased to that, while the BSER of combustion controls from subpart KKKK should be maintained. There was consistent agreement among these commenters that the subcategory of small combustion turbines with base load ratings less than or equal to 50 MMBtu/h of heat input should be maintained in subpart KKKKa. One commenter indicated that turbines with base load ratings less than 20 MMBtu/h should have their own subcategory.

The EPA agrees with the commenters that it is appropriate to maintain a subcategory for new combustion turbines with base load ratings less than or equal to 50 MMBtu/h of heat input.

[48] *See* Table 1 in section IV.B.5 of this preamble.

[49] EPA–HQ–OAR–2024–0419. *Summary of Public Comments and Responses: Review of New Source Performance Standards for Stationary Combustion Turbines and Stationary Gas Turbines.*

[50] *See* sections IV.B.3–7 of this preamble and Table 1 in section IV.B.5 of this preamble for information about the final BSER determinations and $NO_X$ standards of performance for all new, modified, or reconstructed stationary combustion turbines in subpart KKKKa.

[51] The base load rating only includes the heat input to the combustion turbine engine and does not include the rated input from associated duct burners.

[52] *See* 89 FR 101317 (Dec. 13, 2024).

As described in sections IV.B.3–5 of this preamble, the Agency has further examined the available controls for the source category and their reasonableness based on the varying characteristics of different types of combustion turbines. At proposal, the EPA believed that 250 MMBtu/h represented an inflection point above which SCR would be cost-reasonable at intermediate and high levels of utilization (and therefore the BSER) and below which SCR would not be cost-reasonable (and combustion controls would comprise the BSER) except for high-utilization turbines. However, based on updated information, the Agency is not determining that SCR is the BSER for any units smaller than 850 MMBtu/h. There is therefore no reason to define the boundary between small and medium combustion turbines at 250 MMBtu/h.[53]

Moreover, the EPA's review also indicates that the available combustion controls for turbines with base load ratings less than or equal to 50 MMBtu/h of heat input are more limited and can achieve different emission reductions relative to combustion turbines with base load ratings greater than 50 MMBtu/h of heat input.[54] For example, the manufacturer guaranteed $NO_X$ emission rates for these small combustion turbines is generally 25 ppm based on the use of dry combustion controls. However, as the size of the combustion turbine increases above 50 MMBtu/h, manufacturers have developed more effective dry combustion controls with manufacturer guaranteed $NO_X$ emissions rates decreasing to 15 ppm. This includes many models of industrial and frame type combustion turbines larger than 50 MMBtu/h and smaller than 250 MMBtu/h that would have fallen into the proposed small turbine subcategory. These differences between combustion turbines smaller or larger than 50 MMBtu/h and the availability and performance of the different combustion controls each sized group can employ leads the Agency to conclude that subpart KKKK's size-based cutoff of 50 MMBtu/h between small and medium combustion turbines remains the appropriate threshold for differentiating between small- and medium-sized combustion turbines in subpart KKKKa.

The EPA disagrees with commenters that a subcategory for new combustion turbines with base load ratings less than or equal to 20 MMBtu/h of heat input is appropriate, as there are no significant differences in the performance of new combustion controls for turbines less than or equal to 20 MMBtu/h and combustion turbines greater than 20 MMBtu/h and less than or equal to 50 MMBtu/h.[55] However, combustion controls that achieve emission rates of 25 ppm or lower for small combustion turbines are not available for certain existing small combustion turbines that modify or reconstruct, and SCR is not cost reasonable. Therefore, the EPA agrees that a subcategory for combustion turbines with base load ratings less than or equal to 20 MMBtu/h of heat input—with higher $NO_X$ standards based on application of different BSER—is appropriate for modified and reconstructed combustion turbines only.

The EPA is finalizing, as proposed, that subpart KKKKa will not include additional subcategories for new, modified, or reconstructed small combustion turbines to distinguish between those that are electrical drive versus those that are mechanical drive. While the EPA did receive comments requesting that it maintain the distinction between electrical and mechanical drive turbines as in subpart KKKK, the Agency does not believe it is necessary given that the final rule does not treat new and reconstructed combustion turbines the same way, and existing electrical or mechanical drive turbines that modify or reconstruct can meet the final $NO_X$ standards of performance for small modified or reconstructed units in subpart KKKKa using combustion controls.[56]

In subpart KKKKa, after completion of the technology review and consideration of comments provided by stakeholders, the EPA is finalizing the same size-based subcategory approach as the previous combustion turbine criteria pollutant NSPS (subpart KKKK). The final subcategories in subpart KKKKa include combustion turbines with base load ratings greater than 850 MMBtu/h of heat input (*i.e.,* large), those with base load ratings greater than 50 MMBtu/h and less than or equal to 850 MMBtu/h of heat input (*i.e.,* medium), and those with base load ratings less than or equal to 50 MMBtu/h of heat input (*i.e.,* small). Like subpart KKKK, these subcategories are based on the base load rating of the turbine engine and do not include any supplemental fuel input to the heat recovery system.

b. Subcategorization Based on Utilization

In the proposed rule, in addition to subcategorizing combustion turbines according to size, the EPA proposed to subcategorize stationary combustion turbines further depending on 12-calendar-month capacity factors (*i.e.,* utilization). Although the EPA had not previously subcategorized on this basis in subparts GG or KKKK, it has differentiated between combustion turbines on the basis of utilization in other contexts since 2015.[57] Subcategorizing on this basis is appropriate for combustion turbines in the utility sector because a source's pattern of operation (*e.g.,* how often it is in operation over different time frames) generally tracks with how turbines are configured (*e.g.,* as simple cycle versus combined cycle, *etc.*). Patterns of utilization and configuration in turn impact the feasibility, emission reductions that would be achieved by, and cost-reasonableness of different types of $NO_X$ emissions controls. For example, in the utility sector, project developers do not typically construct combined cycle combustion turbine systems to serve peak demand where they would be expected to start and stop often. Similarly, project developers in the utility sector do not typically construct and install simple cycle combustion turbines to operate at higher capacity factors to provide base load power. Combustion turbines used in the utility sector typically fall into both the medium and large subcategories. Similar patterns exist for combustion turbines used in the commercial, institutional, and industrial power generating sectors, which are typically turbines in the small and medium subcategories. In the non-utility sector, project developers typically construct CHP turbines for high-utilization applications and simple cycle turbines for low-utilization applications, such as providing backup power. Thus, turbine utilization is a useful proxy for certain characteristics of turbines—classes, types, sizes, and modes of operation—that are relevant for the systems of emission reduction that the EPA may

[53] The EPA noted in the proposal that ''if the EPA were to determine that SCR was not an appropriate BSER for all small stationary combustion turbines, then it may be appropriate to adjust the size-based thresholds such that turbines of greater than 50, 100, or 150 MMBtu/h of heat input should be treated as 'medium' turbines.'' 89 FR 101318.

[54] *See* the discussion of the determination of the BSER and $NO_X$ standards for new small combustion turbines in section IV.B.5.c of this preamble.

[55] *See* the manufacturer specification sheet in the rulemaking docket for additional information about available models of stationary combustion turbines.

[56] *See* section IV.B.6 of this preamble for discussion of the subcategory for small modified and reconstructed combustion turbines.

[57] *See, e.g., Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units* (88 FR 33318; Oct. 23, 2015).

evaluate to be the BSER and therefore for the resulting standards of performance.

While it is generally the case that utilization tracks turbine size and mode of operation (*e.g.,* simple versus combined cycle), there are exceptions. Industrial mechanical drive applications (*i.e.,* not electric generating) primarily use turbines from the small and medium subcategories but have different utilization characteristics. These turbines tend to operate at more variable loads as compared to combustion turbines used to generate electricity. Their frequent operation may result in their subcategorization as high-utilization facilities, but they are primarily in simple cycle configurations because heat recovery is generally not a technically or economically viable option. However, the amount of utilization and the mode of operation remain relevant for the systems of emission reduction that the EPA may evaluate to be the BSER and therefore for the resulting standards of performance.

The EPA proposed that combustion turbines with 12-calendar-month capacity factors greater than 40 percent would be subcategorized as high capacity factor (*i.e.,* base load or high-utilization) units, those with capacity factors greater than 20 percent and less than or equal to 40 percent were proposed to be subcategorized as intermediate capacity factor/utilization units, and those with capacity factors less than or equal to 20 percent were proposed to be subcategorized as low capacity factor/utilization units. The proposed capacity factor/utilization thresholds were chosen to reflect what, at proposal, were believed to be reasonable cut points above and below which different $NO_X$ controls would be cost-effective based on sources' operational characteristics. The proposed thresholds were also designed to align with thresholds in the 2024 NSPS for greenhouse gas (GHG) emissions from new combustion turbines.[58]

The EPA received significant comments on the subcategorization of stationary combustion turbines according to capacity factor (*i.e.,* utilization). Several commenters recommended that the upper capacity factor threshold for defining small low-utilization combustion turbines be increased to at least 25 percent or as high as 40 percent in subpart KKKKa to not restrict the operation of simple cycle peaking units that will have to support higher demand variability in the future due to increased deployment of intermittent generation. According to the commenters, a lower capacity factor threshold coupled with an emission limit based on SCR would exacerbate the risk and complexity of operating combustion turbines essential for grid firming generation and reliability during extreme weather events and seasonal demands, and constraining these assets could lead to capacity shortfalls that increase the potential of higher-emitting generation being called upon. Another commenter stated that the EPA should set the capacity factor-based subcategories in subpart KKKKa to better reflect the changing operational characteristics for certain combustion turbines used in simple cycle mode and the typical capacity factors of combined cycle units. Specifically, the commenter stated that an annual capacity factor of 60 percent is a more appropriate demarcation between simple cycle and combined cycle turbines. The commenter expects that some frame type simple cycle turbines will be required to operate at capacity factors of more than 40 percent in the future as demand for power climbs, largely due to the boom in artificial intelligence and the associated data centers. In addition, the commenter stated that a threshold of 60 percent would help differentiate between units that operate in simple cycle mode and those that operate in combined cycle mode.

Based on the EPA's updated analysis of the cost and feasibility of available controls for combustion turbines, the Agency is determining in this final rule that SCR does not qualify as the BSER for any subcategory of stationary combustion turbines with 12-calendar-month capacity factors less than or equal to 45 percent.[59] Therefore, the proposed ''intermediate load'' subcategory that would have covered combustion turbines operating at annual capacity factors greater than 20 percent and less than or equal to 40 percent is no longer necessary. Moreover, the EPA has not found differences in the reasonableness of combustion controls based on a combustion turbine's utilization that would make distinguishing between ''low'' and ''intermediate'' load turbines appropriate. Therefore, the proposed low-utilization threshold referenced by the commenter is not included in final subpart KKKKa.

After deciding that three utilization-based subcategories are unnecessary and shifting to just two in this final rule (''high utilization'' and ''low utilization''), the EPA further considered the cutoff between these two subcategories. To determine an appropriate capacity factor that generally reflects the differences between turbines that operate in simple cycle mode and those that operate in combined cycle mode, the EPA evaluated the 12-calendar-month capacity factors of simple cycle turbines in the electric utility power sector that have commenced operation since January 1, 2020. To account for variability, the EPA calculated the 99 percent confidence maximum capacity factor for each combustion turbine. The 99 percent confidence maximum 12-calendar-month capacity factor for recently constructed simple cycle turbines was 43 percent. To account for potential future uncertainty, the EPA is finalizing a 12-calendar-month utilization rate threshold of 45 percent to delineate between low- and high-utilization turbines.[60] [61]

In this final rule, the EPA is subcategorizing large and medium combustion turbines as high- or low-utilization units depending on 12-calendar-month capacity factors (*i.e.,* utilization rates). The high-utilization subcategories include large and medium turbines utilized at 12-calendar-month capacity factors greater than 45 percent. The low-utilization subcategories include large and medium combustion turbines utilized at 12-calendar-month capacity factors less than or equal to 45 percent. Large and medium combustion turbines that exceed the 12-calendar-month capacity factor threshold of 45 percent will be subject to the high-utilization $NO_X$ standards, and owners or operators of such facilities must achieve the applicable $NO_X$ standard, presumably through the operation of additional emission control technology relative to that required for low-utilization combustion turbines. The EPA is not subcategorizing small combustion turbines by utilization and the same BSER and emissions standard is applicable to all new small combustion turbines regardless of the utilization level because utilization level is not determinative of the

[58] *See* 89 FR 39798, 39913 (May 9, 2024). The EPA proposed to repeal the 2024 NSPS for GHG emissions for new combustion turbines, as well as for other new and existing fossil fuel-fired power plants, on June 17, 2025. 90 FR 25752.

[59] *See* sections IV.B.3 and IV.B.5 of this preamble.

[60] While the fleetwide average capacity factor of both medium and large simple cycle turbines is increasing, the average and maximum capacity factors of both medium and large simple cycle turbines that have recently commenced operation has remained relatively constant.

[61] *See* section IV.B.2.g of this preamble for discussion of the EPA's decision not to establish subcategories based on whether a combustion turbine operates in a simple cycle or combined cycle configuration.

reasonableness of $NO_X$ controls for these units.

Even combustion turbines that operate at consistent utilization levels for the life of the facility, the 12-calendar-month utilization rates vary over the life of the turbine. To estimate the variability in 12-calendar-month utilization rates, the EPA reviewed the maximum 12-calendar-month capacity factors and the average capacity factors of combined cycle and simple cycle turbines in the power sector that have commenced operation since 2020. The median percentage that the maximum capacity factor is greater than the average capacity factor is 11 percent for combined cycle turbines and 15 percent for simple cycle turbines. Assuming this is the only factor impacting the relationship between the maximum and average capacity factor, the maximum 12-calendar-month capacity factors of combined cycle and simple cycle turbines with average capacity factors of 40 percent is 44 and 46 percent, respectively. Therefore, the EPA used a 45 percent applicability threshold as representative of combustion turbines with an average capacity factor of 40 percent. The 40 percent value was used when evaluating cost and other BSER factors for control technologies for combustion turbines in the high-utilization subcategories. The EPA acknowledges that this approach is conservative. Once that investment is made, the control technology would likely be used for the life of the facility even if the combustion turbine were to be subcategorized as low utilization in the future. For example, in the utility sector, the average 30-year capacity factor of combined cycle and simple cycle combustion turbines is 51 percent and 9 percent, respectively. Combined cycle turbines initially operate on average at a capacity factor of 66 percent, and by year 30, the capacity factor drops to 37 percent.[62] Simple cycle combustion turbines initially operate at a capacity factor of 13 percent and drop to 5 percent by year 30. For combined cycle and simple cycle turbines, the maximum capacity factor is 28 percent higher and 49 percent higher than the 30-year lifetime average capacity factor, respectively. In conclusion, the EPA determined it is appropriate to use a 40 percent utilization rate when evaluating the BSER factors, but this translates for implementation purposes into a utilization subcategory threshold of 45 percent based on the 12-calendar-month capacity factor to accommodate for the variability of a combustion turbine that operates at a consistent utilization over the life of the unit.

c. Subcategorization Based on Efficiency

The Agency noted in the proposed rule that ''[t]he EPA's review of combustion turbine emissions data and applied control technologies . . . demonstrates a correlation between the efficiency of new turbine designs and $NO_X$ emissions using combustion controls.'' [63] We went on to state that turbine manufacturers have endeavored to increase the efficiency of new turbine designs, but that there is a tradeoff between efficiency and $NO_X$ emissions such that some models of large higher efficiency turbines cannot meet a 15 ppm $NO_X$ standard.[64] We discussed and requested comment on the relationship between turbine efficiency and the effectiveness of combustion controls in our analysis of combustion controls for large combustion turbines.[65] Based on comments received in response to its requests, the EPA is determining that it is appropriate to further subcategorize large low-utilization combustion turbines in subpart KKKKa based on the manufacturer's design efficiency rating.

When subpart KKKK was finalized in 2006, the largest available aeroderivative combustion turbine had a base load rating of less than 850 MMBtu/h of heat input, and less efficient frame units greater than 850 MMBtu were available with manufacturer guaranteed $NO_X$ emission rates of 15 ppm or less. Thus, the subcategories in subpart KKKK were designed to reflect the distinctions between the sizes and feasibility of different types of combustion controls between more efficient turbines that were less than 850 MMBtu/h and less efficient turbines that were greater than 850 MMBtu/h.

Since subpart KKKK was finalized, incremental advances have been made to the design of the aeroderivative turbine that had been used to define the 850 MMBtu/h threshold, and the base load rating of that specific turbine model is now approximately 1,000 MMBtu/h.[66] Further, new frame type turbines have become available that have higher efficiencies. The most common way to increase the efficiency of a combustion turbine is to increase the firing temperature. However, an increase in firing temperature also results in increased formation of thermal $NO_X$. Several frame turbines have become commercially available since 2013 that have design efficiencies of at least 38 percent on a HHV basis [67] and guaranteed $NO_X$ emission rates of 25 ppm. In essence, the state of the source category has evolved since 2006 so that there are now more types of large combustion turbines available, and those combustion turbines have a broader range of efficiencies, which affects $NO_X$ formation and the emission reductions that can be achieved using combustion controls. Given the subsequent development of the industry and the EPA's further understanding of how large, higher efficiency turbines are operated today (*i.e.,* of the intersection between size, utilization, and efficiency), for the purposes of subpart KKKKa, the Agency is determining it is appropriate to subcategorize large, low-utilization combustion turbines depending on whether their design efficiency is less than 38 percent or greater than or equal to 38 percent.[68]

Several commenters requested that the EPA consider subcategorizing large combustion turbines further to reflect the performance of available combustion controls in relation to the utilization and design efficiencies of certain classes or types of available combustion turbines. Other commenters stated that the EPA should revise the size-based subcategories in subpart KKKKa to capture and accommodate variations within certain classes of combustion turbines that could bear significantly on the cost of $NO_X$ controls. Specifically, commenters suggested that the EPA should create additional subcategories for large combustion turbines to distinguish between classes of turbines with distinct $NO_X$ profiles and for which SCR has materially different marginal costs and benefits. The commenters asserted that doing so would account for variation in the BSER, $NO_X$ reductions, and cost effectiveness for three classes of large

[62] At year 24, combined cycle turbines would become low-utilization turbines and the NSPS BSER would no longer be based on the use of SCR. The EPA costing analysis assumes the high-utilization BSER (*i.e.,* SCR) continues to operate the entire 30-year period. Assuming the SCR ceases operation in year 24 would decrease the cost effectiveness of SCR.

[63] 89 FR at 101325.

[64] *Id.*

[65] *See, e.g., id.* at 101333 (solicitation for comment on whether combustion controls are being developed for large, high-efficiency turbines currently guaranteed at 25 ppm that would reduce the $NO_X$ emission rate).

[66] The larger version became available in 2013. See the Excel file docket item titled *combustion turbine manufacturer specifications proposal docket number EPA–HQ–OAR–2024–0419–0020 attachment 3.*

[67] This value is equal to a design efficiency rating of 42 percent on a lower heating value (LHV) basis.

[68] This characteristic was not analyzed or understood to be relevant at the time the BSER analysis was conducted for subpart KKKK.

frame turbines used in the power industry. Specifically, the commenters suggested the following:

• Simple cycle frame turbines (90 to 150 MW) with a $NO_X$ performance standard of 5 ppm reflecting advanced DLN combustion controls as BSER for intermediate and base load. The performance standard should be 15 ppm based on DLN for the low-utilization subcategory.

• Simple cycle frame turbines (200 to 320 MW) with a performance standard of 9 ppm reflecting advanced DLN combustion controls as BSER for intermediate and base load. The performance standard should be 15 ppm based on DLN for the low-utilization subcategory.

• Simple cycle frame turbines (greater than 320 MW) with a performance standard of 25 ppm reflecting DLN combustion controls as BSER for all load subcategories. There is no advanced DLN technology for these very large turbines.

• All units in combined cycle mode (*i.e.,* base load) with a performance standard based on SCR as BSER.

The EPA agrees with the commenters that since subpart KKKK was finalized in 2006, new higher efficiency classes of frame type combustion turbines have become commercially available, and the sizes of these large turbines range from approximately 290 MW to 450 MW. There are also two aeroderivative turbine designs that are large higher efficiency units with $NO_X$ emission rates of 25 ppm.[69] As pointed out by the commenters, these classes of combustion turbines are generally larger than earlier generation designs and these frame type turbines are differentiated from earlier models by their higher firing temperatures that result in higher $NO_X$ emissions.[70]

As discussed above, the EPA is determining that it is appropriate to further subcategorize large, low-utilization combustion turbines according to efficiency. The new subcategorization approach for these turbines reflects the distinctions between large, higher efficiency turbines and large, lower efficiency turbines when those turbines are operating at low levels of utilization. This distinction is not relevant when these turbines are operating at high utilization because, regardless of the efficiency of the turbine, combustion controls with the addition of SCR is reasonable for large turbines operating at high utilization.[71] However, at low utilization, there is a clear distinction between the technical feasibility of achieving different emission rates using combustion controls based on the efficiency of the turbine. Efficiency is thus an appropriate basis for subcategorization for large combustion turbines operating at low utilization.

Further subcategorization according to design efficiency is only reasonable for combustion turbines in the large subcategory. For instance, the EPA is not aware of any commercially available models of new medium combustion turbines with design efficiencies greater than 38 percent on a HHV basis. For the subcategory of new small combustion turbines, the most efficient model of which we are aware achieves an efficiency of 35 percent on a HHV basis. Regardless of the design efficiencies of new small and medium combustion turbines, we did not identify a distinct correlation between efficiency and the manufacturer guaranteed $NO_X$ emission rates. On the other hand, for combustion turbines in the large subcategory, we identified a clear correlation between design efficiency and manufacturer guaranteed $NO_X$ emissions.

For subpart KKKKa, the EPA determines this additional subcategorization is appropriate because it reflects, in part, improvements in the design efficiency of stationary combustion turbines. These developments in the current combustion turbine marketplace—as evidenced by a review of manufacturer specification data and as stated in public comments—continued to evolve since the promulgation of subpart KKKK in 2006. Additionally, distinguishing between combustion turbines in subpart KKKKa based on utilization has the effect of elucidating distinctions in the reasonableness of controls when turbines are operating at low versus high utilization; these distinctions were not evident based on the subcategorization approach in subpart KKKK. As discussed in section IV.B.5 of this preamble, this results in a higher $NO_X$ emissions standard for the class of large low-utilization higher efficiency combustion turbines relative to subpart KKKK. It also results in a lower $NO_X$ emissions standard for the class of large low-utilization lower efficiency combustion turbines than was determined for other classes of large turbines in subpart KKKK.

The EPA notes that subcategorizing large low-utilization combustion turbines by design efficiency can impact the availability of large turbines for use as high-utilization units. For example, combined cycle facilities can be built in stages—initially the simple cycle portion is installed and the HRSG and steam turbine are installed later. This occurs when developers elect to go ahead and install the simple cycle portion to meet current low-utilization loads, and as demand increases over time, they add the steam portion of the combined cycle facility to meet high-utilization loads. Under this planned staging of construction and generation, the combustion turbine could operate as a simple cycle unit for years. For other installations, the simple cycle portion of the combined cycle facility is completed prior to the remainder of the combined cycle facility due to unforeseen events, such as delays in the availability of materials necessary to complete the steam portion of the facility or delays in the availability of a second (or third) combustion turbine engine for a combined cycle facility with multiple turbines serving a single steam turbine. The ability to begin operating the simple cycle portion of the facility prior to the completion of the combined cycle project could have significant financial benefit to the developer and provide additional resources to assist in grid stability. And because the SCR for combined cycle turbines is included in the HRSG, the simple cycle turbine would be operating without SCR in both scenarios.

Without a subcategory for large low-utilization combustion turbines based on efficiency, developers would not be able to use models with efficiencies of 38 percent or greater as simple cycle turbines—even on a short-term basis. The lack of a subcategory would provide a perverse regulatory incentive to install lower efficiency combustion turbines so that they could be operated on a short-term basis in simple cycle mode. This would result in higher overall emissions because when the HRSG becomes operational, the resulting lower efficiency combined cycle facility with a lower efficiency turbine engine would have higher emissions compared to these higher efficiency turbine engines that result in a more efficient and lower emitting combined cycle facility.

d. Subcategorization of Non-Natural Gas-Fired Combustion Turbines

Consistent with subpart KKKK, the EPA proposed that when a combustion turbine fires a fuel that is more than 50 percent non-natural gas (*e.g.,* either a gaseous fuel, such as hydrogen, or a liquid fuel, such as oil) while under full load for a portion of an hour of operation, then that combustion turbine

[69] Variations of the General Electric (GE) LMS100.

[70] Examples include GE's 7HA series (7HA.01, 7HA.02, and 7HA.03), Siemens' 9000HL, and Mitsubishi's M501J series that includes the M501JAC.

[71] *See* section IV.B.3 of this preamble.

is subject to the appropriate non-natural gas $NO_X$ emission standard—based on the application of the BSER—for that entire hour of full-load operation. However, we also solicited comment on eliminating the 50 percent requirement so that the non-natural gas emissions standard would apply when any amount of non-natural gas fuel is burned in the combustion turbine engine at full load. In general, we proposed that the BSER for most sources firing non-natural gas fuels is the use of wet combustion controls (*i.e.,* water or steam injection) and/or diffusion flame combustion. (Diffusion flame combustion is where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. Generally, it is not considered a type of combustion control technology per se because the EPA is not aware of diffusion flame combustors broadly available that are able to achieve significant $NO_X$ reduction in combustion turbines, though for some subcategories the EPA identifies this technology as the BSER in the absence of any other method of control.) Accordingly, we proposed $NO_X$ standards for non-natural gas-fired sources in subpart KKKKa based on the application of the BSER for each size-based subcategory.

Several commenters opposed the EPA's proposal to define sources in subpart KKKKa as non-natural gas-fired when more than 50 percent of the heat input is from a non-natural gas fuel at full load. For example, according to one commenter, widespread industry practice when switching from natural gas to oil is to reduce load and switch from lean premix/DLN combustion controls (for natural gas) to diffusion flame (for oil). This can lead to a short-term spike in emissions, which, according to the commenter, necessitates a higher, less stringent $NO_X$ limit. Should such a spike in $NO_X$ emissions occur when less than 50 percent of the fuel being combusted is fuel oil, the source would be subject to the (lower, more stringent) $NO_X$ standard for natural gas.[72] Commenters further explained that given the effect on emissions of switching fuels, it could be difficult for a source to meet a lower $NO_X$ standard for natural gas combustion when a non-natural gas fuel is being combusted, including when the non-natural gas fuel represents less than 50 percent of the total heat input during the hour. The commenters asserted that a more reasonable approach would be to apply the highest applicable $NO_X$ emissions standard for *any* hour when *any* amount of non-natural gas fuel is combusted—as in the Industrial Boiler NESHAP—and pointed out the EPA's acknowledgement in the proposal that eliminating the 50 percent threshold "could provide a more accurate representation of the performance of applicable control technologies."[73 74]

Other commenters stated the EPA's concern that eliminating the 50 percent requirement would incentivize operators to burn a small amount of non-natural gas fuel to be subject to a higher $NO_X$ emissions limit is unfounded. Specifically, the commenters asserted that reducing load makes fuel switching impractical by causing generation to be less efficient, meaning there is little to no incentive for an operator to conduct a fuel switch to take advantage of a less stringent standard.

Further, several commenters responded to a solicitation for comment in the proposal regarding whether multiple fuels could be combusted simultaneously in a combustion turbine engine and whether it is necessary to temporarily cease operation or reduce load to switch from natural gas to distillate oil. According to commenters, the design and operation of combustion systems do not allow for multiple fuels to be combusted simultaneously in turbines operating under full load—except for specific designs of dual-fuel combustion turbines used in certain industrial processes. The commenters explained that for combustion turbines not designed to operate in dual-fuel mode, different gaseous fuel streams can be premixed and fired (*e.g.,* natural gas and refinery fuel gas or natural gas and hydrogen). A combustion turbine operator cannot simply switch between liquid and gaseous fuels while operating at full load if the turbine is not designed for dual-fuel operation. In general, most combustion turbines are not dual-fuel designs and either start on gas or oil and continue to operate on the same fuel as the unit loads, or, to improve reliability in cold weather, units will start on gas and transition to oil at or before the full speed no load (FSNL) operating condition. In all cases, turbines with dry or wet combustion controls never operate at full load while simultaneously firing both natural gas and fuel oil. The combustion characteristics of the higher hydrocarbon, distillate oil differ from the combustion characteristics of natural gas. These fuels are incompatible with systems that were engineered for methane gas, most notably regarding poor flashback margin, which can result in significant damage to premixed, dry combustion controls.

In subpart KKKKa, the EPA is maintaining the provision from subpart KKKK that non-natural gas hours are defined as any hour when more than 50 percent non-natural gas fuels are fired in the combustion turbine at full load (*i.e.,* when the heat input is greater than 70 percent of the base load rating). In these situations, the non-natural gas $NO_X$ standard applies for the entire reporting hour—even if non-natural gas fuel was fired for only a portion of the hour.[75] Specifically, if the total heat input is greater than 50 percent from non-natural gas fuels (*e.g.,* distillate oil, hydrogen, and fuels other than natural gas), the combustion turbine is subject to the applicable $NO_X$ standard in the non-natural gas-fired subcategory and that $NO_X$ standard must be met for the entire hour. This is consistent with the approach for subcategorizing hours based on load. For example, if the turbine is operated at part load (*i.e.,* 75 percent and 70 percent of the base load rating in subparts KKKK and KKKKa, respectively) at any point during the hour, the part-load standard is applicable for the entire hour even if the average load exceeds the full load threshold. While the EPA appreciates commenters' explanation that fuel switching to obtain more lenient emissions standards is unlikely to occur because it is not economical, the 50 percent non-natural gas threshold has proven workable in subpart KKKK and retaining this threshold in subpart KKKKa avoids any regulatory incentive to unnecessarily combust small amounts of non-natural gas fuels. Similarly, if multiple fuels are burned during an hour of operation and the total heat input is less than or equal to 50 percent non-natural gas (and more than 50 percent natural gas), then the turbine is subject to a $NO_X$ limit that is prorated based on the heat input of the fuels during the hour. For example, if a turbine burns 75 percent by heat input natural gas and 25 percent non-natural gas, the applicable hourly $NO_X$ standard is 0.75 times the applicable natural gas standard, plus 0.25 times the applicable non-natural gas standard.[76]

[72] See Table 1 in section IV.B.5 of this preamble for the $NO_X$ standards for subcategories of natural gas-fired stationary combustion turbines.

[73] *See* 40 CFR part 63, subpart DDDDD.

[74] *See* 89 FR 101318 (Dec. 13, 2024).

[75] For example, an affected facility could burn 51 percent non-natural gas fuel for 1 minute of an hour and 100 percent natural gas for the remaining 59 minutes. In this extreme situation, the entire hour would be considered a non-natural gas-fired hour.

[76] This example assumes the natural gas and non-natural gas fuels are using different fuel nozzles. If the fuels are mixed prior to combustion, the natural gas/non-natural gas determination is based on the

It is important to make clear that the $NO_X$ standards for natural gas and non-natural gas hours apply *only* when combustion turbines are operating at *full load.* As explained by commenters, most combustion turbines decrease load during fuel switching, and regardless of the heat input from a particular fuel being fired for a portion of an operating hour, those turbines would be subject to the part-load $NO_X$ standards, which are higher than the individual natural gas- and non-natural gas-fired $NO_X$ standards. See section IV.B.2.f of this preamble for an explanation of subcategorization for turbines operating at part load.

In subpart KKKKa, the EPA is also finalizing as proposed, with one exception, that the $NO_X$ standards of performance are based on the type of fuel being burned in the combustion turbine engine alone. Fuel choice impacts combustion turbine engine $NO_X$ emissions to a greater degree than it impacts such emissions from a duct burner. Therefore, the EPA concludes that this approach provides a more accurate representation of the performance of applicable control technologies. The natural gas standard applies at those times when the fuel input to the combustion turbine engine meets the definition of natural gas, regardless of the fuel, if any, that is burned in the duct burners. The one exception is for byproduct fuels. For turbines burning byproduct fuels, the applicable emissions standard is based on the total heat input to the turbine, including and fuel burned in the duct burners. See section IV.B.7.d of this preamble for further discussion of turbines burning byproduct fuels.

e. Subcategory for Temporary Combustion Turbines

At proposal, the EPA requested comment on creating either a subcategory or an exemption for stationary combustion turbines used in temporary applications. Many commenters generally supported some form of streamlined compliance for temporary applications. Some commenters raised concerns that a full exemption could have unintended consequences. After considering these comments, the Agency is finalizing a new subcategory in subpart KKKKa for small and medium stationary combustion turbines (*i.e.,* up to 850 MMBtu/h in size) used in temporary applications. This subcategory reflects a BSER determination of combustion controls with an associated standard of 25 ppm $NO_X$ when combusting natural gas and 74 ppm $NO_X$ when burning non-natural gas fuels, along with a streamlined approach to compliance that primarily relies on maintaining documentation of manufacturer certification. Such turbines may be used in a single location for up to 24 months. The EPA is also amending subpart KKKK to include an optional subcategory for stationary temporary combustion turbines with the same BSER, $NO_X$ standards, and recordkeeping and reporting requirements as for the subcategory of stationary temporary combustion turbines in subpart KKKKa.[77]

As discussed in the proposal, a streamlined approach to NSPS compliance for temporary combustion turbine applications would bring this NSPS into alignment with similar approaches that are available in the boilers NSPS and in the reciprocating internal combustion engines (RICE) NSPS. The EPA has historically considered portable boilers and RICE used for limited periods of time to be temporary equipment not subject to regulation under their respective NSPS or NESHAP subparts.[78] The Agency observed at proposal that the absence of any such provisions in the combustion turbines NSPS is anomalous insofar as combustion turbines tend to have lower air pollutant emissions than are emitted by an equivalent level of power generation from RICE. Further, in the proposal, the EPA noted that the permitting, testing, and monitoring requirements typically applicable for a combustion turbine subject to an NSPS may not be appropriate or suitable for combustion turbines needed quickly and only for limited periods of time. Temporary combustion turbines are generally operated in short-term situations but can also provide power during extended emergency or emergency-like situations (*e.g.,* a natural disaster damages the electric grid) while the primary generating equipment is not available, while transmission and/or generation capacity is being repaired and/or upgraded, or for some other unforeseen event.[79] Since permitting itself could take longer than the need for temporary generation, the Agency solicited comment on whether an applicability exemption or subcategorization would be appropriate for temporary combustion turbines under subparts GG, KKKK, and KKKKa.

The EPA also requested comment at proposal on whether the BSER for temporary combustion turbines is the use of combustion control technology consistent with the otherwise applicable subcategory—25 ppm $NO_X$ for units with base load ratings of 850 MMBtu/h or less and 15 ppm $NO_X$ for larger units. Relatedly, we solicited comment on the appropriate testing and recordkeeping criteria for such regulatory provisions.

Multiple commenters supported the idea of a subcategory or exemption. Comments, particularly from industry stakeholders, supported a BSER of combustion controls and indicated that turbines used in temporary applications are generally capable of meeting a $NO_X$ standard of 25 ppm using combustion controls. The same commenters also generally opposed requiring SCR for temporary turbines, the complexity of which would tend to defeat the purpose of being able to bring in such turbines quickly for immediate and short-term power supply. The EPA agrees that combustion controls are the BSER for temporary turbines, and the Agency applies the BSER analysis set forth in section IV.B.3 of this preamble explaining why SCR is not the BSER for small and medium turbines.

The Agency is limiting the scope of the temporary combustion turbines subcategory so that large combustion turbines (*i.e.,* those with a base load rated heat input greater than 850 MMBtu/h) cannot qualify for treatment as temporary combustion turbines. In general, large combustion turbines are not used in temporary applications—these turbines tend to be frame type units that are more challenging to transport and operate without more extensive onsite preparation.

The EPA finds 25 ppm to be the appropriate standard of performance for $NO_X$ emissions from temporary combustion turbines. (The EPA is not establishing a separate $SO_2$ standard of performance for this subcategory—in other words, the otherwise applicable $SO_2$ standard will apply).) Most trailer-mounted turbines, which would likely be intended to remain in the same location for less than 2 years and so can be considered representative of typical temporary turbines, have standard

fuel mixture. If the mixture meets the definition of natural gas, the natural gas standard is applicable. And if the mixture does not meet the definition of natural gas, the non-natural gas standard is applicable.

[77] The emission standards for temporary turbines are consistent with the standards in subpart KKKK.

[78] *See, e.g.,* 40 CFR 60.4200(a), 60.4230(a), 60.40b(m), and 60.40c(i). (We note that at proposal we inadvertently cited similar but separate provisions of the RICE NSPS related to ''replacement'' engines. *Cf.* 40 CFR 60.4200(e), 60.4230(f).)

[79] Note that a separate exemption is available for ''emergency turbines'' in subpart KKKK, which is also being included in subpart KKKKa. *See* 40 CFR 60.4310(a); *id.* 60.4420 (definition of ''emergency combustion turbine''). However, this provision may not be clearly applicable in all circumstances in which temporary turbines are needed.

emission guarantees of 25 ppm $NO_X$. There are some trailer-mounted turbines with lower standard emission guarantees, but these are less efficient designs with lower rated outputs. For example, an emissions standard of 15 ppm $NO_X$ would limit the availability of temporary turbines to those less efficient models with lower rated outputs—significantly increasing costs for the regulated community and resulting in increased fuel use. Combustion systems capable of achieving 15 ppm $NO_X$ are generally more complex and physically larger than comparable combustion systems capable of achieving 25 ppm $NO_X$. For example, more complex combustion control systems generally have more fuel nozzles and burners, premix larger amounts of air with the fuel, and have more sophisticated control systems. This increases the physical size and cost of a combustion turbine for a given rated output. Furthermore, aeroderivative turbines are generally physically smaller than frame units for the same rated output. Most aeroderivative turbines have guaranteed emission rates of 25 ppm $NO_X$. The ability to transport a temporary turbine is a critical feature and an emissions standard of less than 25 ppm $NO_X$ would increase the physical size per rated output of combustion turbines that could meet that emissions standard and undermine the purpose of the subcategory. In addition, as discussed in section IV.B.4 of this preamble, combustion controls capable of achieving 25 ppm $NO_X$ qualify as the BSER for small combustion turbines and low-utilization medium turbines—both of which are potential temporary turbines. While some medium temporary turbines may operate at high utilization levels for limited periods of time, there will be periods when the turbine will be in storage, being transported to a new location, or otherwise not operating. On balance, the EPA anticipates that medium temporary turbines will have utilization levels of less than 45 percent. Therefore, we conclude that combustion controls capable of achieving 25 ppm $NO_X$ are the BSER for the temporary turbines subcategory.

Commenters recommended increasing the allowable period of operation at a single location to 18 months or 2 years to account for situations where temporary power is needed for longer than the 12-month period mentioned in the proposal. The Agency agrees with commenters that a 12-calendar-month period may not be sufficient for all situations. In addition, a 24-month period is consistent with a longstanding policy within the Prevention of Significant Deterioration (PSD) permitting program, which recognizes that emissions occurring for no longer than that period of time may be considered temporary and therefore excluded from modeling analysis.[80] We note that 24 months is the total residence time permitted from when a temporary turbine commences operation. The final temporary turbine subcategory is for turbines used at a single location for up to 24 months.

Some commenters also stated that the subcategory should be available to combustion turbines used in temporary applications regardless of whether they meet criteria for portability. To simplify compliance and avoid potentially complicated regulatory determinations, the EPA is not requiring temporary combustion turbines to be portable in nature or meet indicia of portability to qualify for this subcategory.[81] Commenters noted there may be applications where a temporary combustion turbine can be transported to a location and installed onsite for a time-limited purpose, but may not meet a definition of ''portable'' such as that included, for example, in the definition of ''temporary boilers.'' [82] Given other criteria the EPA is finalizing that limit the scope of a new subcategory for temporary combustion turbines, we agree a requirement to be portable serves little benefit and is not needed.[83]

Monitoring, recordkeeping, and reporting requirements are substantially reduced for the subcategory of temporary turbines. In the final rule, the EPA is requiring only that the owner or operator of a turbine falling within the temporary turbines subcategory maintain documentation onsite that each temporary turbine has been certified by its manufacturer to meet a $NO_X$ emissions rate of 25 ppm, and that each turbine has been performance tested at least once in the prior 5 years (for turbines older than 5 years, after the initial sale by the manufacturer). Annual performance testing is not required for turbines in the temporary subcategory. We anticipate that a test every 5 years will be sufficient to ensure that temporary turbines are properly maintained so as to continue to meet the 25-ppm limit.

Consistent with the proposal, the EPA finds that several conditions on the use or replacement of temporary turbines are necessary to ensure the subcategory does not inadvertently create a means of avoiding requirements that apply under the NSPS for turbines used in non-temporary capacities. Under the final rule, should a temporary combustion turbine remain in place for longer than 24 months, then it would not be considered temporary for any period of its operation, and any failure of the owner or operator to comply with the otherwise applicable requirements of the relevant NSPS, even in the initial 24 months of operation, would be an enforceable violation of the Act. In addition, the final rule does not allow the replacement of a temporary combustion turbine with another temporary combustion turbine to maintain temporary status beyond the 24-month period. However, as an anticipated normal function for these types of turbines, temporary turbines may be used to replace or substitute the generation provided by non-temporary turbines (or other types of generators) when those units are taken offline (*e.g.,* for maintenance work). In addition, the relocation of a temporary stationary combustion turbine within a facility does not restart the 24-calendar month residence time.

The EPA is not finalizing a complete exemption from the NSPS for temporary combustion turbines. In response to the alternative exemption approach on which the Agency sought comment, multiple commenters supported an exemption approach like the NSPS for RICE. However, for RICE, the exemption from the NSPS for equipment operating in a single location of up to 12 months works in conjunction with regulations promulgated under title II of the Act to bring these RICE within the definition of ''nonroad engines'' as set forth at 40 CFR 1068.30. Such units are then subject to regulations that the EPA has promulgated for nonroad engines pursuant to title II of the Act.[84]

Under both the statute and EPA regulations, combustion turbines in general are considered a kind of internal combustion engine that therefore could in theory be regulated as nonroad engines.[85] Historically, however, the EPA has not regulated combustion turbines, even those that may be portable, as nonroad engines, but rather

[80] *See* 43 FR 26380, 26394 (June 19, 1978).

[81] Note that combustion turbines that are mounted on a vehicle for portability continue to be subject to the NSPS, as they have been under subparts GG and KKKK. *See, e.g.,* 40 CFR 60.4420 (definition of ''stationary combustion turbine'').

[82] *See* 40 CFR 60.41b.

[83] Note that, as a separate matter, to be considered a ''nonroad engine'' for purposes of mobile source regulation under Title II, a unit must, among other things, meet the criteria in the definition at 40 CFR 1068.30, paragraph 1, such as being ''portable or transportable.''

[84] *See* 42 U.S.C. 7547; *see also, e.g.,* 40 CFR 60, subparts IIII and JJJ; 40 CFR part 1039.

[85] *See* 42 U.S.C. 7550(1) and 7602(z).

as stationary sources.[86] The current definition of ''nonroad engine'' at 40 CFR 1068.30 excludes engines that are subject to an NSPS. All combustion turbines meeting the applicability criteria of the NSPS for combustion turbines are subject to those NSPS standards (including portable turbines) and thus have been excluded from the definition of nonroad engines. An exemption from the NSPS for qualifying stationary temporary applications would potentially bring portable combustion turbines within the definition of nonroad engine at 40 CFR 1068.30. However, the kinds of turbines that are used in stationary temporary applications are not currently subject to any title II regulations or standards. Finalizing an exemption for temporary or portable combustion turbines without ensuring a workable framework for compliance under title II could leave these engines subject to no emission standards at all.

Nonetheless, the Agency recognizes the significant interest several stakeholders have expressed in treating combustion turbines used in stationary temporary applications as nonroad engines subject to regulation under title II. There could be benefits in the form of reduced permitting burden and further streamlined compliance obligations for the purchasers and users of such turbines. At the same time, manufacturers of combustion turbines that are treated as nonroad engines would be subject to compliance obligations under title II, including, for example, obtaining certificates of conformity. Such turbines would be treated as other nonroad engines under title II and permitting requirements would not apply to emissions from the engine because such turbines would no longer be considered a part of the stationary source. Commenters on this rule identified concerns with the air quality effects if many temporary combustion turbines were brought together and operated in a single location and suggested imposing operating or total-emissions constraints and air quality considerations to prevent these consequences.[87]

The EPA believes these matters deserve further investigation before rulemaking action is taken to consider regulating portable combustion turbines used in temporary applications under title II rather than under the NSPS. The EPA is not promulgating any such regulations under title II in this action. In this final rule, the EPA is including a conditional exclusion in subpart KKKKa that will exclude combustion turbines from the definition of ''stationary combustion turbine,'' if the turbine meets the definition of ''nonroad engine'' under title II of the Act and applicable regulations, and is certified to meet emission standards promulgated pursuant to title II of the Act, along with all related requirements. This provision will become operative if the EPA in the future adopts nonroad emission standards and certification requirements for portable combustion turbines.

Even in the absence of a complete exemption from the NSPS, the EPA believes creating the subcategory for temporary combustion turbines in this action can facilitate actions that reduce the permitting burden faced both by sources and permitting authorities. Note that the EPA is separately exercising authority granted to it under CAA section 502(a) to exempt from title V permitting any combustion turbines that are not major sources.[88] The EPA expects that the application of combustion turbines at sites with a potential to emit below the title V permitting major source threshold (as referenced in the last sentence of CAA section 502(a)) would also emit below major NSR emissions thresholds and thus only be subject to minor NSR program requirements. CAA section 110(a)(2)(C) requires States to develop a program to regulate the construction and modification of any stationary source, including minor NSR requirements as necessary, to assure that NAAQS are achieved. Minor NSR requirements are required to be approved into a State Implementation Plan (SIP), Tribal Implementation Plan (TIP), or Federal Implementation Plans (FIP) and are often mechanisms to assist in achieving and maintaining the NAAQS.[89] The CAA and the EPA's regulations are less prescriptive regarding the minor NSR program requirements. Therefore, reviewing authorities generally have significant flexibility in designing their minor NSR programs, including any air permitting programs for minor sources. Minor NSR permits are almost exclusively issued by State, local, and other authorized reviewing authorities, although the EPA issues minor NSR permits for most areas of Indian country where Tribes have not developed TIPs or requested delegation to administer minor NSR air permitting programs for their jurisdictions. With the creation of the temporary combustion turbines subcategory in this action, the EPA believes authorized reviewing authorities may find it efficient to pursue further streamlining of minor-source permitting for such sources, including developing a general permit for such sources, or issuing a permit by rule for these sources.

Even where temporary combustion turbines comprise or are part of a major source for purposes of NSR permitting, the temporary turbines subcategory will assist States in identifying emissions from such sources that may be excluded from parts of the permit review because they are temporary. Under the EPA's PSD regulations, temporary emissions can be excluded from the analysis of whether the emissions increases that would result from construction or modification of a major stationary source cause or contribute to a violation of air quality standards.[90] As discussed above, the 24-month period we are finalizing for this subcategory accords with the duration the EPA has used for decades to classify temporary emissions in the PSD program. Sources with characteristics that place them within this subcategory will have a straightforward means of showing that emissions from these sources are temporary to apply this PSD exemption for temporary emissions in the review of a PSD permit application.

Further, the standards of performance in this final rule are legally and practically enforceable and thus can serve to inform calculations of the potential to emit of these sources for purposes of determining whether they are major sources for NSR applicability purposes. Sources may, of course, also voluntarily accept, in an enforceable permit condition, more stringent emissions limits, or limit their operating time, to reduce their potential to emit so as to become synthetic-minor sources for NSR applicability purposes.

f. Subcategory for Combustion Turbines Operating at Part Loads, Located North of the Arctic Circle, or Operating at Ambient Temperatures of Less Than 0 °F

When the EPA promulgated subpart GG (the original stationary gas turbine criteria pollutant NSPS) in 1979, the $NO_X$ standards and compliance requirements were based on performance testing. Based on subsequent rulemakings, owners or

[86] *See* 42 U.S.C. 7411(a)(3). *See* 40 CFR 60.331(a); 40 CFR 60.4420 (definition of ''stationary combustion turbine'').

[87] The EPA notes that under the subcategory approach to temporary stationary combustion turbines, which was are finalizing in subpart KKKKa, permitting authorities may take these kinds of considerations into account in determining appropriate emissions limitations or other requirements.

[88] *See* section IV.E.5 of this preamble for further discussion.

[89] *See* 42 U.S.C. 7410(a)(2)(C).

[90] *See* 40 CFR 51.166(i)(3); 40 CFR 52.21(i)(3).

operators of a gas turbine subject to subpart GG with a $NO_X$ CEMS began determining excess emissions on a 4-hour rolling average basis. The EPA found that a 4-hour basis is the approximate time required to conduct a performance test using the performance test methods specified in subpart GG. This 4-hour rolling average became the default for determining the emission rates of gas turbines, and, in 2006, the EPA retained it in the subsequent review of the stationary combustion turbine criteria pollutant NSPS.

When the EPA proposed subpart KKKK in 2005, the $NO_X$ performance emissions data were based on stack performance tests, which are representative of emission rates at high hourly loads, rather than CEMS data. The final $NO_X$ standards for high hourly loads were consistent with the performance test data and manufacturer guarantees. To avoid confusion with the annual ''utilization'' levels discussed elsewhere in this document, we will refer to high hourly loads as ''full loads,'' in contrast with ''part loads''; utilization levels on an annual basis are referred to as ''low-utilization'' and ''high-utilization.'' Manufacturer guarantees are only applicable during specific conditions, which include the load of the combustion turbine (*i.e.,* when the load meets certain specifications) and the ambient temperature (*i.e.,* generally above 0 °F). When combustion turbines are operated at part loads and/or at low ambient temperatures, low-$NO_X$ combustion controls—the identified BSER in subpart KKKK—were not as effective at reducing $NO_X$ from a technical standpoint.[91] At part-load operation and low ambient temperatures, it is more challenging to maintain stable combustion using DLN and adjustments to the combustion system are required—resulting in higher $NO_X$ emission rates. Therefore, in subpart KKKK, the Agency identified diffusion flame combustion as the BSER for hours of part-load operation or low ambient temperatures.[92]

In subpart KKKK, a part-load hour is defined as any hour when the heat input rate is less than 75 percent of the base load rating of the combustion turbine. If the heat input rate drops below 75 percent at any point during the hour, the entire hour is considered a part-load hour, and the part-load standard is applicable during that hour. Determination of the 4-hour emissions standard is calculated by averaging the four previous hourly emission standards. Under this approach, the ''full load'' standard (*i.e.,* the standard of performance that has been established for the relevant subcategory as discussed elsewhere in this notice) would not be applicable until a minimum of 6 continuous operating hours. The initial and final hours would be startup and shutdown, respectively, and the part-load standard is applicable during those hours. If the combustion turbines were operating at full load during the middle 4 hours, the full load standard would be applicable to that 4-hour average. The emission standards for the remaining hours would be a blended standard that is between the part-load and full load standards. This approach was viewed as appropriate to account for the different applicable BSERs. Subpart KKKK also includes a 30-operating-day rolling average standard that is applicable to combustion turbines with a HRSG. The 30-operating-day rolling average was included in subpart KKKK because the HRSG was part of the affected facility, and a longer averaging period is necessary to account for variability when complying with the alternate output-based emissions standard.

The EPA is finalizing the same short-term 4-hour standard for part load in subpart KKKKa along with the blended standard approach. Specifically, the applicable emissions standard is based on the heat input weighted average of the four applicable hourly emissions standards. However, as discussed at proposal, the EPA is finalizing two changes to the part-load subcategory. First, the CEMS data analyzed by the EPA indicates that emissions tend to slowly increase at lower loads, but, in general, combustion turbines can maintain compliance with the emissions standards at hourly loads of 70 percent and greater, not just at loads of 75 percent and greater, as reflected in subpart KKKK.[93] Therefore, the EPA determines in subpart KKKKa that this subcategory applies for any hour when the heat input is less than or equal to 70 percent of the base load rating. The EPA notes that lowering the part-load threshold brings more operating periods under the otherwise-applicable standards of performance.

Second, the EPA is finalizing a different size threshold for subcategorizing the part-load emission standards. Subpart KKKK subcategorizes the part-load emissions standard based on the rated output of the turbine (*i.e.,* combustion turbines with outputs greater than 30 MW have a more stringent part-load standard than smaller combustion turbines). For subpart KKKKa, the EPA proposed to subcategorize the part-load standard based on the heat input rating (*i.e.,* turbines with base load heat input ratings greater 250 MMBtu/h would have a more stringent standard (96 ppm $NO_X$) than smaller combustion turbines at part load (150 ppm $NO_X$)).

In this action, since the final size-based subcategorization approach no longer includes the proposed 250 MMBtu/h of heat input size threshold for combustion turbines operating at full load, and because the proposal did not otherwise identify a basis for amending the part-load size threshold, the EPA is retaining in subpart KKKKa a size threshold that is comparable to the 30 MW output threshold in subpart KKKK. However, instead of using an output metric, subpart KKKKa sets a threshold to distinguish the two size-based, part-load subcategories at less than, or equal to or greater than, 300 MMBtu/h of heat input. All new combustion turbines with base load ratings of greater than 300 MMBtu/h have design rated outputs of greater than 30 MW, and all new combustion turbines with base load ratings of less than 300 MMBtu/h have design rated outputs of less than 30 MW. This maintains consistency with the use of a heat-input metric for other size-based subcategories in the NSPS.

In the proposed rule for subpart KKKKa, the EPA solicited comment with respect to a concern that the standards for the part-load subcategory are significantly less stringent than the otherwise applicable standards of performance and could create a perverse incentive to operate at part loads. The Agency also solicited comment on possible solutions. Commenters largely disagreed that the part-load standards substantially eroded the stringency of the NSPS or created a perverse incentive for sources to operate at lower hourly

[91] The ambient temperature of combustion turbines located north of the Arctic Circle would often be below 0 °F, and these units are included in the low ambient temperature subcategory regardless of the actual ambient temperature. As we found with subpart KKKK, the costs of requiring combustion controls that would rarely be used are not reasonable.

[92] Combustion turbines have multiple modes of operation that are applicable at different operating loads and when the combustion turbine is changing loads. The modes are specific to each combustion turbine model. The identified BSER of diffusion flame combustion also includes periods of operation that use less effective DLN compared to operation at full loads.

[93] To maintain flame stability during part-load operation, dry combustion controls must increase the relative amount of the fuel going to the diffusion flame portion of combustion system. This inherently results in an increase in the $NO_X$ emissions rate. Similarly, to maintain stable operation during part-load operation, the relative amount of water injected for wet combustion controls must be reduced.

loads to obtain the higher emissions standards. One commenter submitted graphical data illustrating that it typically will not be economically advantageous to operate at part-load for extended periods of time, and other commenters that own or operate combustion turbines stated that extended part-load operations are not consistent with their practices.

After considering these comments, the EPA agrees that further changes from subpart KKKK's approach to part-load operations are not needed in subpart KKKKa. The EPA finds the commenters' explanations credible that the part-load subcategory does not unduly weaken the NSPS. Nonetheless, as the EPA discussed in the proposal, we believe the use of an optional, alternative approach to compliance using mass-based limits could be an effective way to simplify compliance for some combustion turbines while also ensuring overall good emissions performance consistent with the revised standards of performance in subpart KKKKa.[94]

Additionally, in subpart KKKKa, the EPA is maintaining as proposed the same ambient temperature subcategorization and BSER as in subpart KKKK. If at any point during an operating hour the ambient temperature is below 0 °F, or if the combustion turbine is located north of the Arctic Circle, the BSER is the use of diffusion flame combustion with the corresponding part-load standard.

Dry combustion controls are less effective at reducing $NO_X$ emissions at part-load operations and low ambient temperatures. In addition, SCR is only effective at reducing $NO_X$ under certain temperatures at part loads and is not as effective at reducing $NO_X$ as at design conditions. The only technology the EPA has identified for all part-load operations and/or low ambient temperatures is the use of diffusion flame combustion. Therefore, in subpart KKKKa, the EPA determines that diffusion flame combustion is the BSER for these conditions as proposed.[95]

g. Subcategorization Based on Other Factors

In response to the proposed rule, several commenters recommended that subpart KKKKa subcategorize stationary combustion turbines based on whether they operate as simple or combined cycle units and/or whether they are aeroderivative or frame type units. These commenters recommended that the EPA re-evaluate its BSER determinations to better address the physical and operational differences between simple and combined cycle turbine configurations because of the technical and economic effects these differences have on controlling emissions. Specifically, the commenters cited the higher exhaust temperatures of simple cycle frame turbines and noted the challenges this would create for operating SCR. One commenter noted that due to the different capabilities of the equipment, the base load subcategory should be split so that simple cycle and combined cycle units are not in the same group.

While the EPA appreciates the differences between these types of units and discusses such differences as appropriate throughout this preamble, it is not subcategorizing based on simple versus combined cycle or aeroderivative versus frame type combustion turbines in subpart KKKKa. For aeroderivative and frame type combustion turbines, separate subcategories might not be technically viable. For example, aeroderivative turbines share components and are adapted from aircraft jet engines, and while they tend to be lighter and have higher pressure ratios and efficiencies than similar-sized frame units, there is overlap and no clear distinction between the technologies. In addition, and critically, there are no inherent differences in the performance of combustion controls or SCR between aeroderivative and frame type combustion turbines.[96]

Further, the EPA believes it is more appropriate to address the differences between combustion turbines operating in simple cycle and combined cycle configurations through subcategorizing by utilization.[97] While there are clearly differences between simple and combined cycle configurations, those differences are not necessarily determinative of the reasonableness of different types of $NO_X$ controls because they are superseded by another basis or bases for subcategorization. That is, there are other characteristics of turbines that, when accounted for under the EPA's subcategorization approach in this final rule, obviate the need to subcategorize by simple cycle versus combined cycle configuration because such differences are already effectively accounted for by the utilization subcategories.

In the utility sector, simple cycle turbines tend to operate at much lower capacity factors (*e.g.,* the average lifetime capacity factor is 9 percent) than combined cycle turbines (*e.g.,* the average lifetime capacity factor is 51 percent). However, there is some overlap in capacity factors. For example, in 2024, 3 percent of simple cycle turbines operated at capacity factors greater than 30 percent, and 19 percent of combined cycle turbines operated at capacity factors less than 30 percent. As discussed in section IV.B.2.b of this preamble, the capacity factor or utilization level impacts the cost effectiveness of $NO_X$ controls. This is the case regardless of whether a turbine is in a simple cycle versus a combined cycle configuration. After accounting for utilization (in addition to the other types of subcategorizations the EPA is providing in this final rule), there is no further basis for differentiating between simple and combined cycle turbines from the perspective of selecting the BSER and standards for $NO_X$. Furthermore, establishing separate subcategories could create a regulatory incentive to install simple cycle turbines instead of combined cycle turbines—although the same controls are reasonable for both, and simple cycle turbines emit more $NO_X$ per unit of useful energy output. To avoid this perverse environmental outcome, the EPA is establishing standards of performance that are achievable by both simple and combined cycle combustion turbines under the subcategories in this final rule. In addition, to establish separate subcategories for simple and combined cycle turbines, the Agency would have to determine how to subcategorize CHP facilities that operate with and without an associated steam turbine, turbines using steam injection, and recuperated turbines. While these turbines recover energy from the turbine exhaust, that energy is not necessarily used to generate electricity with a steam turbine, so these would not be considered a combined cycle since they are not using two separate thermodynamic cycles. However, since these types of combustion turbines are recovering thermal energy and the exhaust gas temperatures are lower, the costs of SCR are lower compared to simple cycle turbines. The EPA notes that new CHP facilities often replace existing boilers (or boilers that would have been built if CHP were not installed) and offer significant environmental benefit compared to generating the electricity and thermal

[94] *See* section IV.E.4 of this preamble for discussion of the optional, alternative mass-based $NO_X$ standards.

[95] A BSER of diffusion flame combustion includes DLN that is less effective at reducing $NO_X$ than DLN under design conditions.

[96] *See* the manufacturer specification sheet in the rulemaking docket for additional information about available models of stationary combustion turbines.

[97] *See* discussion in section IV.B.2.b of this preamble.

energy separately. Increasing the costs of new small, medium or low-utilization CHP to the point that sources are disincentivized from using CHP could have the perverse environmental outcome of increasing overall emissions. The Agency has considered these broader impacts in determining not to subcategorize between simple and combined cycle turbines.

3. Evaluation of SCR Under BSER Factors

In the proposal of subpart KKKKa in December 2024, the EPA proposed to find SCR justified under the BSER factors for combustion turbines of all sizes, albeit not below a 40 percent capacity factor for turbines equal to or smaller than a base load rating of 250 MMBtu/h of heat input, and not below a 20 percent capacity factor for turbines larger than that size.[98] Since the proposal, the EPA has undertaken a review of the BSER criteria in relation to SCR considering the extensive technical comments submitted. The EPA's closer evaluation of cost information concerning SCR as well as information concerning the difficulty of application of SCR for certain subcategories, and other downsides of SCR in terms of its emissions and energy impacts have led the EPA to conclude that SCR is not justified under the BSER factors for all but new large high-utilization combustion turbines.

The EPA is determining for subpart KKKKa that SCR is part of the BSER for new large high-utilization stationary combustion turbines (*i.e.,* that are utilized at 12-calendar-month capacity factors greater than 45 percent). For these types of combustion turbines, SCR has been nearly universally adopted in recent years, and the EPA has determined it is cost-effective, achieving substantial reductions in $NO_X$ emissions at costs that are comparable to those that the EPA has found reasonable in other rules over the past several decades. The EPA received no significant, adverse comments asserting that SCR is not appropriately part of the BSER for this subcategory of new combustion turbines.

A review of recent rules and determinations, multiple relevant cost metrics, and the adoption of SCR technology across certain types and sizes of power sector stationary combustion turbines in recent years, all support our determination that this technology is cost-reasonable for the subcategory of large high-utilization turbines, to which we apply it as BSER in subpart KKKKa.

However, for all other combustion turbine subcategories, the EPA is determining that SCR is not part of the BSER under present circumstances. For these other subcategories, SCR is not cost reasonable in relation to the amount of $NO_X$ emission reductions that can be achieved, presents implementation and operational challenges, has high energy impacts, and has other non-air quality and environmental impacts that are not justified in relation to the relatively small reduction in $NO_X$ emissions beyond the standards that can be achieved with combustion controls.

The SCR process is based on the chemical reduction of $NO_X$ via a reducing agent (reagent) and a solid catalyst. To remove $NO_X$, the reagent, commonly ammonia ($NH_3$, anhydrous and aqueous) or urea-derived ammonia, is injected into the post-combustion flue gas of the combustion turbine. The reagent reacts selectively with the flue gas $NO_X$ within a specific temperature range and in the presence of the catalyst and oxygen to reduce the $NO_X$ into molecular nitrogen ($N_2$) and water vapor ($H_2O$). SCR employs a ceramic honeycomb or metal-based surface with activated catalytic sites to increase the rate of the reduction reaction. Over time, however, the catalyst activity decreases, requiring replacement, washing/cleaning, rejuvenation, or regeneration to extend the life of the catalyst. Catalyst designs and formulations are generally proprietary. The primary components of the SCR include the ammonia storage and delivery system, ammonia injection grid, and the catalyst reactor. The technology can be applied as a standalone $NO_X$ control or combined with other technologies, including wet and dry combustion controls.

The EPA's proposed BSER of combustion controls with the addition of post-combustion SCR for most new and reconstructed combustion turbines generated a significant adverse response from the regulated community and certain States during the public comment period. Other commenters supported broad application of SCR as the BSER.

Many commenters stated that the proposed BSER is problematic and impractical because it would require SCR on industrial combustion turbines as well as those that operate at variable loads. According to the commenters, this would introduce significant operating complexity, increase annual operating costs, and result in unreasonable costs and operating burden for these installations. Instead, these commenters argued that the need for SCR should be determined on a site-specific basis as part of NSR air permitting.

Additionally, commenters stated that SCR systems on simple cycle turbines are complicated, expensive, and pose design challenges when compared to combined cycle operations. For example:

- SCR systems require specific temperature ranges to operate effectively, typically between 315 °C and 400 °C (600 °F and 750 °F). For simple cycle turbines with higher exhaust temperatures, additional cooling air may be needed to cool the exhaust flow and avoid damage to the SCR catalyst structure and operation. The costs associated with installation, operation, and maintenance of such cooling air systems were not adequately addressed by the EPA in the proposal.
- The installation of SCR systems requires sufficient space for the catalyst and ammonia injection systems. Therefore, it can be infeasible to install SCR on an existing installation that is modifying or reconstructing; the cost of SCR on a simple cycle frame turbine can be 30 percent to 50 percent of the cost of the turbine alone while doubling the space requirements.
- SCR is difficult even for combined cycle units in the case of existing turbines going through modifications or reconstructions. An existing turbine may have been installed without SCR in mind, so replacement of the HRSG could be required for a combined cycle unit, which is more expensive (estimated at $50 million) than the SCR system itself (estimated at $14 million).
- SCR systems are generally more effective in steady-state operations. Combustion turbines that frequently start and stop or operate under variable loads could face challenges in optimizing SCR performance.
- Implementing and operating an SCR system involves not only engineering, design, and installation costs but also additional maintenance and operational costs, including the handling and storage of ammonia or urea, catalyst replacement, and monitoring. For this reason, SCR is not viable for remote sites that have no full-time operator (*e.g.,* unattended compressor stations).
- The EPA developed the proposed limits based on utility data, not data adequately characterizing industrial installations. The EPA should revise its cost analysis, which will demonstrate the requirement to achieve emissions rates associated with SCR is inappropriate for non-utility units.

Due in part to these concerns, several commenters stated that the EPA underestimated the cost for SCR relative

[98] *See* 89 FR 101322–23.

to recent cost estimates received from manufacturers and technology providers and submitted information to that effect. Furthermore, the commenters contended that considering more accurate cost estimates, SCR costs would not be ''relatively low,'' as the EPA stated at proposal, and the technology would not be the BSER for medium and small combustion turbines, including industrial turbines, low-utilization turbines, and existing sources that modify or reconstruct.

These commenters stated that the EPA should re-analyze its proposed BSER determination based on the design and operational differences among different types of combustion turbines. In addition, commenters provided several cost estimates that result in the incremental cost effectiveness of installing SCR at values generally greater than $20,000/ton $NO_X$ abated to achieve the proposed $NO_X$ emissions limits, which exceed the levels that the EPA has historically considered to be cost effective.

Taking into consideration the SCR cost information submitted by commenters, the EPA has updated the BSER cost analysis from proposal. This cost analysis supports a conclusion that the BSER for most subcategories of new, modified, or reconstructed combustion turbines subject to subpart KKKKa is the use of combustion controls alone (*i.e.,* without SCR). The updated cost analysis nonetheless also supports our conclusion that SCR is the BSER for large high-utilization turbines—turbines with base load ratings greater than 850 MMBtu/h of heat input that are utilized at capacity factors greater than 45 percent on a 12-calendar-month basis. The new combustion turbines subject to a standard of performance based on the BSER of combustion controls with SCR have, over the past 5 years, almost exclusively used combined cycle technology and have operated as base load units (*i.e.,* at high utilization rates). This means that the technical issues associated with SCR raised by commenters are not a factor for new large high-utilization sources in this subcategory.

a. Adequately Demonstrated

SCR is a mature and well-understood post-combustion add-on $NO_X$ control that has been installed on combustion turbines (both simple and combined cycle), utility boilers, industrial boilers, process heaters, and reciprocating internal combustion engines. Many natural gas-fired combustion turbines in the power sector currently utilize SCR. While costs and operational challenges can vary quite dramatically among different types of combustion turbines in ways that are relevant to other BSER factors (as discussed in the sections that follow), the EPA is not aware that SCR is completely unavailable to any type of natural gas-fired combustion turbine. Therefore, in general the EPA considers SCR to be a technically feasible and available technology for control of $NO_X$ emissions from natural gas-fired stationary combustion turbines. In that sense, SCR can be considered to be ''adequately demonstrated''; however, after considering all of the BSER factors as described in the sections that follow, the EPA finds that SCR in a number of combustion turbine applications is not the BSER for most subcategories of combustion turbines.

For non-natural gas-fired combustion turbines, commenters noted that SCR has not been demonstrated on liquid fuel-fired turbines (including distillate and biofuels) operating at high-utilization rates and that biofuels can poison SCR catalysts. The EPA does not have long-term performance information for various types of non-natural gas-fired combustion turbines and due to potential complications, such as catalyst deactivation due to impurities in the fuel, the EPA is not determining that SCR is technically feasible for all non-natural gas-fired turbines.

b. Extent of Reductions in $NO_X$ Emissions

The percent reduction in $NO_X$ emissions from SCR depends on the level of control achieved through combustion controls. For a combustion turbine using standard combustion controls (*i.e.,* a guaranteed full load emissions rate of 25 p.m. $NO_X$) reductions can approach 90 percent. The percent reduction across SCR is lower if the combustion turbine is equipped with advanced combustion controls. In conjunction with dry combustion controls on natural gas-fired combustion turbines, SCR has been demonstrated to reduce long-term $NO_X$ emission rates to approximately 3 ppm for multiple types of turbines.[99]

c. Costs

In response to significant adverse comments concerning the EPA's proposed cost analysis for SCR, the EPA has revised its cost analysis. The full, final cost analysis is available in the *SCR Costing* technical support document available in the docket for this action.[100] This section summarizes key findings from this updated analysis.

In 2006, when subpart KKKK was promulgated, SCR was evaluated as a potential BSER and was determined to not meet the statutory criteria. The estimated cost of achieving incremental $NO_X$ reductions with the use of SCR was $9,000/ton (adjusted to 2024$) compared to the lean premix and DLN systems that were available at that time. The EPA determined that these costs were not reasonable in promulgating subpart KKKK.

SCR is widely adopted as a $NO_X$ emissions control strategy for certain stationary combustion turbines, particularly for large turbines in the utility sector. However, during the technology review for this action, the EPA found that information contained in the records of permitting actions requiring SCR on combustion turbines is not consistent or well-developed for purposes of informing a detailed cost analysis for an NSPS. Generally, if a source was required (or chose voluntarily) to install SCR and went forward with a new combustion turbine project or installation, the cost of SCR presumably did not undermine the economic viability of that project. Nonetheless, just because individual projects have been economically viable with SCR installation does not necessarily mean SCR installation on all combustion turbines is cost-justified on a national basis, nor does it necessarily reflect the best or most cost-effective means of achieving overall reductions in $NO_X$ emissions. These considerations will be discussed further in sections IV.B.3.c.ii and iii below.

Before proceeding with our evaluation of SCR under the BSER factors, the Agency first notes that standalone SCR (*i.e.,* without combustion controls) is not the BSER. The EPA estimates that SCR without combustion controls would be able to reduce $NO_X$ emissions by 90 percent and achieve emission rates like turbines with 25 ppm and 15 ppm $NO_X$ guarantees based on combustion controls alone. The exact achievable level would depend on the uncontrolled $NO_X$ emissions rate of the relevant turbine. The estimated cost effectiveness of SCR without combustion controls is approximately $5,000/ton for low-utilization large turbines and $2,000/ton for high-utilization large turbines. However, the combustion controls analyzed in this technology review can achieve the same level of emissions reduction at significantly lower cost. As discussed in greater detail in section IV.B.4.c of this

[99] *See* section IV.B.5.a.i of this preamble for discussion of the determination of the $NO_X$ standards of performance for the subcategory of combustion turbines subject to a BSER that includes SCR in subpart KKKKa.

[100] *See* Docket ID No. EPA–HQ–OAR–2024–0419.

preamble, combustion control costs are approximately $2,000/ton for low-utilization large turbines and $100/ton for high-utilization large turbines, without any of the secondary environmental and energy impacts associated with SCR.[101] Therefore, SCR alone is not the BSER for any subcategory. The remainder of this section considers whether SCR should be a part of the BSER, as a technology applied in addition to combustion controls.

For this final rule, as in the proposal, the EPA estimated the capital and operating costs of SCR primarily using information from the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) flexible generation report.[102] The NETL report includes detailed costing information on aeroderivative simple cycle turbines using hot SCR and frame combined cycle turbines using conventional SCR. For information not available in the NETL report, the EPA used information from its cost control manual and applied Agency engineering judgment.[103] One commenter provided detailed comments on the SCR costing analysis that the EPA incorporated, as appropriate, into the cost estimations. Other commenters provided cost comparisons that suggest the costs of SCR for simple cycle turbines have been underestimated.[104]

The EPA determines for purposes of subpart KKKKa that the costs of SCR are reasonable on a nationwide basis for new large high-utilization stationary combustion turbines (*i.e.,* with base load ratings greater than 850 MMBtu/h of heat input and utilized at 12-calendar-month capacity factors greater than 45 percent) and therefore that SCR is part of the BSER for this subcategory. However, for new large low-utilization stationary combustion turbines (*i.e.,* utilized at 12-calendar-month capacity factors less than or equal to 45 percent), and for all medium and small combustion turbines, the EPA determines that the costs of SCR are not reasonable and therefore that SCR is not part of the BSER for these subcategories, particularly in light of the other factors discussed in the following sections.

i. Large High-Utilization Combustion Turbines

Based on information reported to EPA's Clean Air Markets Program Data (CAMPD), most new construction of large high-utilization combustion turbines is projected to be combined cycle facilities. As described in section IV.B.5 of this preamble, the maximum 12-calendar-month capacity factor of recently constructed large simple cycle turbines is less than 45 percent. Large turbines are almost exclusively used to generate electrical power, and at high levels of utilization, the levelized cost of electricity (LCOE) of combined cycle turbines is approximately the same as or lower than the LCOE for simple cycle turbines. Therefore, the EPA's primary costing analysis for large high-utilization turbines is based only on the impacts and costs of using SCR on combined cycle turbines. The costs for large high capacity factor simple cycle turbines are provided for completeness, and while these costs are higher than for combined cycle turbines, simple cycle turbines are generally not expected to operate at the high utilization levels that would trigger the SCR-based BSER subcategory.

There are several indicators that broadly support the cost-reasonableness of SCR as part of the BSER for new large combined cycle turbines that plan to operate at high rates of utilization. The cost of SCR as a percentage of the capital costs associated with constructing a new combined cycle turbine is estimated to be approximately 1 percent. The estimation of spent capital cost for SCR is approximately $3 million to $7 million (2024$) depending on the size of the combined cycle turbine. The capital costs of SCR on a capacity basis range from $10 per kilowatt (kW) to $20/kW, depending on the size of the combined cycle turbine. These costs translate into a relatively low cost per unit of energy output, and their effects on prices or costs to the consumer are relatively small and manageable. Total SCR cost (annualized capital costs, fixed costs, and operating costs) per unit of production (*i.e.,* electricity generation) is approximately $0.66/MWh, which represents a 2 percent increase in the LCOE for a new 370 MW combined cycle combustion turbine operating at a 12-calendar-month capacity factor of 51 percent for 30 years. This effect on the cost of electricity generation compares favorably with cost analyses that have been conducted in the past.[105]

Turning to the $/ton cost-effectiveness metric: In the final cost analysis for this rule, the EPA finds that the cost effectiveness on a $/ton of $NO_X$ controlled basis varies significantly based on the percent reduction and the size of the combined cycle turbine. SCR costs decrease with economies of scale and there is no single $/ton figure that can be used to broadly represent SCR costs.

For combined cycle turbines with combustion controls guaranteed at 25 ppm $NO_X$, the incremental costs to reduce $NO_X$ concentrations to 3 ppm range from $3,200/ton to $4,600/ton.[106] For combined cycle turbines with combustion controls guaranteed at 15 ppm $NO_X$, the incremental costs to reduce $NO_X$ concentrations to 3 ppm range from $4,400/ton to $6,800/ton.[107] For combined cycle turbines with combustion controls guaranteed at 9 ppm $NO_X$, the incremental costs to reduce $NO_X$ concentrations to 3 ppm range from $7,300/ton to $12,000/ton.[108] For combined cycle turbines with combustion controls guaranteed at 5 ppm $NO_X$, the incremental costs to reduce the $NO_X$ concentration to 3 ppm range from $13,000/ton to $22,000/ton.[109]

SCR costs decrease with economies of scale, and the low end of each range is more representative of the typical size of new combined cycle turbines. The EPA has concluded that the costs of SCR for large high-utilization turbines with combustion controls and guaranteed $NO_X$ emission rates of 9 ppm or greater are reasonable. Therefore, for these types of turbines, the EPA finds SCR to be cost-effective. While the Agency finds the incremental costs of SCR from

[101] See section IV.B.3.d of this preamble.

[102] Oakes, M.; Konrade, J.; Bleckinger, M.; Turner, M.; Hughes, S.; Hoffman, H.; Shultz, T.; and Lewis, E. (May 5, 2023). *Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation.* U.S. Department of Energy (DOE). Office of Scientific and Technical Information (OSTI). Available at *https://www.osti.gov/biblio/1973266.*

[103] *EPA Air Pollution Control Manual, Chapter 2 Selective Catalytic Reduction.* June 2019. Available at *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.*

[104] For detailed information on the costing analysis, see the *SCR Costing* technical support document included in the docket for this action.

[105] *See, e.g.,* 80 FR 64510, 64565, tbl. 9 (Oct. 23, 2015). While this comparison is useful to illustrate in a relative sense this cost metric as used in prior EPA analyses, reference to this prior rulemaking notice should not be understood as endorsing any legal of factual determinations made at that time.

[106] The EPA reviewed the previous 5 years of emissions data to determine long-term emission rates of turbines. A long-term emissions rate of 3 ppm $NO_X$ was used for a turbine complying with a short-term emissions rate of 5 ppm $NO_X$. The long-term emissions rate of a turbine with a 25 ppm $NO_X$ guarantee is 20 ppm $NO_X$. Using a long-term emissions rate of 2 ppm or 4 ppm as representative for a combustion turbine with SCR would not change the BSER determinations.

[107] The long-term emissions rate of a turbine with a 15 ppm $NO_X$ guarantee is 14 ppm $NO_X$.

[108] The long-term emissions rate of a turbine with a 9 ppm $NO_X$ guarantee is 7 ppm $NO_X$. The SCR costs are estimated by assuming the SCR uses two catalyst layers instead of three.

[109] The EPA assumed the long-term emissions rate of a turbine with a 5 ppm $NO_X$ guarantee is 5 ppm $NO_X$. The SCR costs are estimated by assuming the SCR uses two catalyst layers instead of three.

a 5-ppm baseline would not be considered cost-effective, the large high-utilization turbines for which the EPA is including SCR in the BSER do not achieve an emissions rate this low with combustion controls alone. (Further, as discussed in more detail below, the EPA is setting the standard of performance associated with SCR at 5 ppm, meaning that to the extent large, high-utilization combustion turbines are, or come to be, capable of achieving 5 ppm with combustion controls alone, SCR would not need to be installed to meet the emissions standard.)

The costs of SCR for new large high-utilization combustion turbines on a per-ton of $NO_X$ abated basis (*i.e.,* $/ton) compare favorably with prior EPA rulemakings that regulate $NO_X$ emissions. Although determinations concerning cost reasonableness in one statutory or programmatic context may not necessarily translate to another, these regulatory precedents offer points of comparison with respect to the same pollutant that can be informative in evaluating the most cost-effective opportunities for abatement of a common pollutant across multiple program arenas and therefore are relevant to the BSER analysis. That is particularly true when the relevant statutory provisions involve cost considerations similar to CAA section 111(a)(1).

In prior NSPS and CAA rules, the EPA generally found incremental costs in the range of $7,400/ton of $NO_X$ abated to be cost effective (escalated to 2024$).[110] The EPA has also recognized that an SCR with incremental costs of approximately $12,000/ton of $NO_X$ abated may be justifiably rejected as not cost-reasonable (escalated to 2024$).[111]

In the proposed rule, the EPA cited the *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard* rulemaking (commonly known as the Good Neighbor Plan), as a comparison point. In that rule, the EPA estimated SCR costs for retrofit applications of $14,000/ton of $NO_X$ abated (escalated to 2024$) as the appropriate representative cost threshold for defining ''significant contribution'' under CAA section 110(a)(2)(D)(i)(I).[112] However, upon further review and taking into account comments with respect to this particular rule comparison, the EPA no longer believes the Good Neighbor Plan is an appropriate comparator. First, we did not grapple at proposal with the Supreme Court's decision to stay enforcement of the Good Neighbor Plan as likely arbitrary and capricious.[113] Although the Court addressed the Agency's failure to consider a different aspect of the problem, its opinion raised significant doubts about the adequacy of the EPA's analysis and engagement with comments received. Because the Good Neighbor Plan was never implemented and its assumptions about cost reasonableness were not tested in the real world, we do not believe the cost analysis in that rule is entitled to significant weight as a regulatory precedent. Second, the cost analysis in the Good Neighbor Plan assessed retrofit costs for coal units for the purpose of promoting attainment of the NAAQS and therefore does not directly translate to the situation here. As noted elsewhere in this preamble, more stringent standards may be appropriate under the specific set of facts presented in an individual permitting context than would be appropriate for a NSPS. Similarly, more stringent standards, and greater associated costs, may be appropriate when necessary to meet statutory requirements for nonattainment areas. Finally, the EPA is in the process of reconsidering the Good Neighbor Plan, and as such, no longer believes this cost-per-ton figure should serve as an appropriate comparison point. Although that process is not yet complete, its initiation reflects the Agency's significant concerns with the analysis and justifications underlying the Good Neighbor Plan.

Turning to simple cycle turbines: The costs of SCR for simple cycle combustion turbines are higher, especially for frame type turbines. SCR catalysts require specific operating temperatures to control $NO_X$ effectively, and the exhaust temperatures of simple cycle turbines are generally too high to be used directly in the SCR. The exhaust gases need to be cooled, generally through injecting tempering air to cool the exhaust to avoid damaging the SCR catalyst. Frame turbines require higher amounts of air tempering than aeroderivative turbines because the exhaust temperature of the most efficient frame-type combustion turbine is approximately 200°C higher than the most efficient aeroderivative combustion turbines. For utility units at high utilization rates, it is generally more cost effective to cool the exhaust prior to the SCR using the HRSG instead of tempering air. Since a HRSG does not increase the volume of exhaust gas entering the SCR, the SCR can be smaller and less costly, and the recovered thermal energy can be used to generate additional useful output. The EPA notes that there are technologies other than air tempering and a traditional HRSG that can be used to cool the exhaust gas prior to the SCR reactor. For example, a new combined cycle turbine could be designed with a relatively simple, lower cost HRSG and the recovered thermal energy (*i.e.,* steam) could be used in a relatively simple, lower cost steam turbine or injected into the combustion turbine itself (*i.e.,* a steam injection combustion turbine). These technologies have efficiencies and costs that range between more standard simple and combined cycle turbine configurations.

To estimate the costs of SCR on large simple cycle turbines, the EPA scaled costs based on the NETL 50 MW simple cycle turbine using dry combustion controls. These costs incorporate tempering air and are more representative of the SCR costs for large simple cycle turbines than the 100 MW simple cycle model plant the EPA used at proposal. The 100 MW aeroderivative model plant is a simple cycle turbine that uses compressor intercooling and wet combustion controls—both of which lower the exhaust temperature and reduce the need for tempering air. In response to specific concerns raised by commenters, the EPA incorporated several of the suggested adjustments to the SCR costing equations.[114] However, for simple cycle turbines, even with these adjustments the EPA's estimated costs are significantly less than the example costs provided by other commenters. Because the EPA finds commenters' information credible and representative, this suggests that actual costs could be as high as twice the EPA's derived costs. Consequently, the EPA's cost analysis for simple cycle turbines likely represents best-case scenario costs.

The cost of SCR as a percentage of the capital costs associated with constructing a new simple cycle turbine is estimated to be approximately 5 percent. The estimation of spent capital cost of the SCR reactor is approximately $8 million to $18 million (2024$), depending on the size of the turbine.

[110] *See, e.g.,* 71 FR 9866, 9870 (Feb. 27, 2006) (finding an incremental cost for SCR on boilers of approximately $5,000/ton to be reasonable).

[111] *See, e.g.,* 77 FR 20894, 20929 (Apr. 6, 2012) (approving State determination rejecting SCR where incremental cost was estimated at $8,845).

[112] *See* 88 FR 36654 and 36746 (June 5, 2023).

[113] *Ohio* v. *EPA,* 603 U.S. 279, 292–94 (2024).

[114] The EPA continues to primarily use SCR costs derived from the NETL Flexible Generation Report. Differences in the final rule include using SCR fixed costs dervied from the EPA's pollution Control Manual, accounting for capacity payments, using the base cost of the combustion turbine without SCR when determining the value of the lost electric sales, and using the six-tenths rule when estimating the capital costs of SCR for different combustion turbine sizes.

The capital costs on a capacity basis range from \$45/kW to \$80/kW, depending on the size of the simple cycle turbine. These costs translate into a higher cost per unit of energy output, and in terms of their likely effect on prices or costs to the consumer, are higher than for combined cycle turbines. Total costs (annualized capital costs, fixed costs, and operating costs) in terms of cost per unit of production (in terms of electricity generation) translate to \$2/MWh, a 4 percent increase in the LCOE for a 240 MW simple cycle combustion turbine operating at a 12-calendar-month capacity factor of 51 percent for 30 years.

For a simple cycle turbine with combustion controls guaranteed at 25 ppm $NO_X$, the incremental costs to reduce the $NO_X$ concentration to 3 ppm range from \$6,800/ton to \$10,000/ton. For a simple cycle turbine with combustion controls guaranteed at 15 ppm $NO_X$, the incremental costs to reduce the $NO_X$ concentration to 3 ppm range from \$10,000/ton to \$16,000/ton. For a simple cycle turbine with combustion controls guaranteed at 9 ppm $NO_X$, the incremental costs to reduce the $NO_X$ concentration to 3 ppm range from \$17,000/ton to \$28,000/ton. And for simple cycle turbines with combustion controls guaranteed at 5 ppm $NO_X$, the incremental costs to reduce the $NO_X$ concentration to 3 ppm $NO_X$ range from \$33,000/ton to \$54,000/ton. While these estimates generally exceed what has historically been considered cost-reasonable for $NO_X$ emissions reductions, the EPA does not anticipate simple cycle turbines will generally fall into the large high-utilization subcategory because they will not be utilized at or above the 45 percent capacity factor on a 12-calendar-month basis. At high levels of utilization, the fuel savings of combined cycle turbine outweigh the increase in capital costs and the large high-utilization subcategory is almost exclusively combined cycle and combined heat and power turbines. Therefore, these costs do not change the EPA's determination that the costs of SCR are reasonable for large high utilization combustion turbines.

ii. Large Low-Utilization Combustion Turbines

The EPA concludes that SCR is not cost-reasonable for all other subcategories of new stationary combustion turbines, including large combustion turbines that are designed and operated as low-utilization units.

Most large low-utilization combustion turbines operate as simple cycle turbines in the utility sector. Historical data indicates that simple cycle turbines in the utility sector typically have utilization rates of less than 20 percent, considerably lower than the 45 percent utilization level that defines the high-utilization subcategory. The long-term, fleetwide average utilization for large simple cycle turbines is approximately 9 percent. While some combined cycle turbines may also occasionally operate below a 45 percent utilization level on a 12-month basis, this is more unusual. Therefore, the EPA uses the costs of SCR for simple cycle turbines rather than combined cycle turbines when evaluating low-utilization turbines.

While some indicators could support the cost-reasonableness of SCR as a part of the BSER for large simple cycle turbines operated at low rates of utilization, others do not. In particular, the EPA finds that the incremental \$/ton cost ranges for $NO_X$ abatement are substantially higher than the EPA has found reasonable in prior rules (see section IV.B.3.c.ii). Therefore, the EPA is determining in subpart KKKKa that the costs of SCR are not reasonable for new large low-utilization combustion turbines.

The EPA estimates using its SCR cost model that the capital cost of SCR as a percentage of the capital costs associated with constructing new simple cycle turbines is estimated to be approximately 3 to 4 percent. The estimation of spent capital cost is approximately \$5 million to \$17 million (2024\$) depending on the size of the simple cycle turbine. The capital cost on a capacity basis ranges from \$40/kW to \$80/kW depending on the size of the simple cycle turbine. These costs translate into significantly higher costs per unit of energy output relative to large high-utilization turbines. Total costs (annualized capital costs, fixed costs, and operating costs) in terms of costs per unit of production (in terms of electricity generation) for a simple cycle turbine operated at a 9 percent capacity factor for 30 years translate to \$8/MWh to \$14/MWh, a 5 to 8 percent increase in the LCOE, depending on the size of the turbine. However, several industry commenters asserted that estimated SCR costs for large simple cycle turbines are far higher than the estimates derived from the EPA's primary data sources. As discussed in the *SCR Costing* technical support document included in the docket, as a reasonable bounding assumption we assume the capital costs that could be experienced by some firms may be up to three times higher than the estimates derived from our primary data sources. Increasing the EPA estimated capital costs by a factor of three results in an increase in the costs of electricity generation for a typical simple cycle turbine that is higher than prior EPA rules. Nonetheless, the EPA notes that at the upper end of the utilization threshold, the increase in the cost of electricity from simple cycle turbines would still be comparable with previous EPA rules.

In contrast, the costs on a per-ton basis, even using the EPA-derived costs, do not compare favorably with prior EPA rulemakings regulating $NO_X$ emissions. The cost effectiveness of the \$/ton of $NO_X$ controlled vary significantly based on the utilization of the simple cycle turbine, the percent reduction, and the size of the simple cycle turbine. Nonetheless, the historical, long-term capacity factor of 9 percent, along with a relatively conservative 25 ppm manufacturer guaranteed emissions rate, is a reasonably accurate representative example. For simple cycle turbines with combustion controls guaranteed at 25 ppm $NO_X$ operating at a 30-year capacity factor of 9 percent, the incremental costs to reduce the $NO_X$ concentration to 3 ppm range from \$27,000/ton to \$46,000/ton. The \$/ton costs would be even higher for turbines with lower guaranteed $NO_X$ emission rates (such as 15 or 9 ppm).[115] The EPA has determined these costs to be not reasonable.

Even assuming a simple cycle turbine is operated at an average capacity factor of 40 percent for 30 years (the upper end of the subcategory threshold), the EPA has determined the costs are not reasonable. For simple cycle turbines with combustion controls guaranteed at 25 ppm $NO_X$, the incremental costs to reduce the $NO_X$ concentration to 3 ppm range from \$8,000/ton to \$12,000/ton. While these costs are closer to the range of costs the EPA has considered reasonable in previous rulemakings, commenters with experience in this area provided information indicating a range of capital costs that may be considerably higher than used in our primary cost analysis. As described earlier in this section, to incorporate this information, we use a three-fold increase in capital cost as a bounding assumption, and we applied adjustments to the cost model to reflect these additional inputs to illustrate the increase in cost that may be associated with SCR installation on at least some large simple cycle turbines. This results in an incremental cost effectiveness of \$15,000/ton to \$25,000/ton. Again, costs on a \$/ton basis would be even higher for turbines with lower guaranteed $NO_X$ emission

[115] *See SCR Costing* technical support document in the docket.

rates based on combustion controls. Therefore, the Agency determines that the costs of SCR are not reasonable for large low-utilization turbines in subpart KKKKa.

iii. Medium and Small Turbines

Unlike the large combustion turbine subcategory, which is dominated by utility units, the medium and small size subcategories include a significant number of combustion turbines used in the industrial and institutional sectors.

The medium low-utilization subcategory is primarily comprised of utility sector simple cycle turbines. Due to economies of scale, the relative costs of SCR are higher for medium simple cycle turbines than for large simple cycle turbines. The incremental control costs of SCR on medium combustion turbines with a guaranteed $NO_X$ emissions rate of 25 ppm range from $32,000/ton to $150,000/ton depending on the turbine size. This corresponds to a 5 to 18 percent increase in the cost of electricity and the $/MWh costs range from $10/MWh to $47/MWh. Even assuming a new medium simple cycle combustion turbine operates near the 45 percent utilization threshold, the incremental control costs range from $9,000/ton to $37,000/ton $NO_X$ abated. The Agency has determined the costs of SCR are not reasonable for any new, modified, or reconstructed medium low-utilization combustion turbines.

The medium high-utilization subcategory is primarily comprised of industrial simple cycle combustion turbines that serve mechanical drive applications, and about one-third of the units operate in either industrial CHP or utility sector combined cycle applications. Consistent with the proposed rule, the EPA used a 30-year capacity factor of 60 percent when estimating the incremental impacts of SCR for CHP and mechanical drive applications. Mechanical drive applications are projected to comprise most of the new medium high-utilization turbines. For medium mechanical drive applications using a turbine with a 25 ppm $NO_X$ guarantee, the incremental control costs range from $10,000/ton to $25,000/ton $NO_X$ abated depending on the size of the turbine. These costs are higher than the Agency considers reasonable. (See prior rule examples in section IV.B.3.c.i.) The control costs would be even higher on a per-ton basis for combustion turbines using combustion controls with lower $NO_X$ guarantees. In addition, turbines with mechanical drive applications tend to be at the smaller end of the medium size subcategory—resulting in even higher control costs (on a $/ton basis) for such units. Finally, commenters provided cost information that suggest the EPA's estimated SCR costs may be unreasonably low for simple cycle turbines.[116] Therefore, SCR does not qualify as the BSER for new, modified, or reconstructed medium mechanical applications.

For medium CHP and combined cycle turbine applications using a turbine with a 25 ppm $NO_X$ guarantee, the $NO_X$ control costs for SCR range from $5,000/ton to $15,000/ton depending on the size of the turbine and the application. For medium CHP and combined cycle turbine applications using a turbine with a 15 ppm $NO_X$ guarantee, the control costs for SCR range from $7,000/ton to $23,000/ton depending on the size of the turbine and the application. The average base load rating of medium institutional and industrial CHP combustion turbines is 220 MMBtu/h, and the corresponding cost of control is $10,000/ton $NO_X$ abated. SCR would not be cost reasonable for medium-sized CHP applications using a turbine with an emissions guarantee less than or equal to 15 ppm $NO_X$.

The average base load rating of medium combined cycle combustion turbines is 740 MMBtu/h, and the corresponding cost of control is $7,000/ton $NO_X$ abated for facilities using a turbine with a guaranteed $NO_X$ emissions rate of 15 ppm. The cost of control for medium combined cycle applications using a turbine with a guaranteed $NO_X$ emissions rate of 9 ppm using combustion controls is $13,000/ton.

Reviewing the cost-estimate ranges for all the types of turbines included in the medium subcategory, we observe that certain cost-per-ton figures at the lower end of the range fall within or approach a level that may be considered reasonable. However, the Agency has determined that it is not appropriate to subcategorize by turbine type (*i.e.,* simple cycle vs. combined cycle or aeroderivative vs. frame type) as discussed earlier in section IV.B.2.g of this preamble. As discussed further in section IV.B.3.d below, issues with SCR on small and medium turbines addressed under other BSER factors, including operational and maintenance challenges, ammonia slip, and energy requirements, tip the scale against SCR as the BSER for any new, modified, or reconstructed medium turbine regardless of size or level of utilization within that subcategory.

Small combustion turbines are used primarily in the industrial and institutional sectors. For small combustion turbines, the incremental costs of SCR for a 50 MMBtu/h combined cycle turbine with $NO_X$ combustion control guarantees of 25 ppm is $13,000/ton $NO_X$ abated. The Agency has determined that this cost is not reasonable. Since SCR costs on a $/ton basis will be even higher for small low-utilization combustion turbines and for small combustion turbines with lower guaranteed $NO_X$ emission rates based on the use of combustion controls, the EPA has determined that the costs of SCR are not reasonable for all new, modified, or reconstructed small combustion turbines regardless of the level of utilization.

iv. Response to Comments Regarding SCR Costs

With respect to the ''cost of emissions reduction'' BSER factor, one commenter opposed the cost analysis presented at proposal as over-reliant on the incremental $/ton metric in evaluating SCR as the BSER. The commenter contended that judicial precedents as well as longstanding EPA practice take a more flexible view of the role of cost, that the cost can be assessed for BSER as a whole rather than by the incremental costs of individual components, and that under CAA section 111, costs simply need not be excessive, *i.e.,* so great that they would drive the industry to ruin.

As an initial matter, the EPA agrees that the Agency has traditionally looked at several metrics to evaluate cost as part of the BSER analysis, and that the statute affords the Agency discretion in how this factor can be considered under CAA section 111(a)(1).[117] In this rulemaking, as the analysis above sets forth, the Agency evaluated costs using those same metrics that have been used in prior NSPS rulemakings, including total cost, cost as a percentage of capital cost, incremental cost-per-ton of pollutant reduced, and cost per unit of production (in this case, electricity production or LCOE). Overall, our cost analysis shows that while some of these cost metrics suggested at proposal that SCR may be cost-reasonable for more subcategories of combustion turbines than the large high-utilization subcategory, the incremental cost-per-ton in many of these circumstances far exceed what the Agency has found to be cost-effective in prior CAA rulemakings. That is particularly true considering the additional information submitted by commenters experienced in the procurement of SCR technologies showing that the EPA underestimated the actual costs of procurement,

[116] *See SCR Costing* technical support document.

[117] *See Lignite Energy Council,* 198 F.3d at 933.

installation, and operation at proposal, which the Agency has since incorporated into its analysis through adjustments to the cost model. In addition, for reasons further explained in the following section, other BSER factors weigh against identifying SCR as the BSER, including that SCR involves ammonia slip, which can lead to the formation of criteria pollutants.

With respect to the claim that the EPA is giving undue weight to the incremental cost effectiveness of SCR and is using more rigid cost tests than supported by relevant case law, the EPA disagrees. Use of that metric here, including the incorporation of emissions reductions achieved through technologies used to comply with existing subpart KKKK as a baseline, is consistent with many prior NSPS rulemakings and applicable case law confirming the EPA's broad discretion in analyzing costs under CAA section 111(a)(1).[118] Particularly in the NSPS technology review context, considering incremental costs and emissions reductions of a relevant emissions technology is necessarily part of the ''review'' required by CAA section 111(b)(1)(B). The EPA has given weight to incremental cost-effectiveness (on a $/ton basis) in evaluating different technologies within BSER analysis in many rules while, as here, also considering several other cost metrics.

The EPA has historically used incremental costing as part of NSPS technology reviews as a way of evaluating whether the marginal cost of an adequately demonstrated additional emissions control supports selecting that control as the BSER. For example, when the EPA first determined SCR to be the BSER for coal-fired utility boilers, we used the existing NSPS standards, which were based on combustion control technologies, as the baseline when determining whether the incremental costs of SCR were reasonable and whether the technology qualified as the BSER.[119] That cost analysis was upheld by the D.C. Circuit in *Lignite.*[120] In addition, when the EPA later reviewed the NSPS for coal-fired electric generating units, the Agency evaluated the incremental impacts of additional $NO_X$ reductions from the SCR when determining the amended emissions standard and did not include the reductions from the use of combustion controls when determining the cost effectiveness of the amended emissions standard.[121] Furthermore, when promulgating subpart KKKK, the EPA did not use the original NSPS subpart GG as the baseline, because the $NO_X$ performance standards in subpart GG were primarily based on diffusion flame combustion, and the EPA recognized that combustion controls would meet BSER factors. Thus, the Agency first evaluated the level of combustion control that could be achieved and then determined if the incremental impacts of SCR were reasonable.[122] The EPA has also considered incremental costs in any number of other NSPS rulemakings in addition to these.[123] The EPA disagrees with commenter's assertion that considering the incremental costs of a technology from a baseline of either an existing standard or a less costly emissions control technology is inconsistent with longstanding practice or case law.

Further, cost-effectiveness figures evaluated across other CAA rules and programs provide a meaningful comparison to assist in determining what level of cost has generally been considered cost-effective for reducing emissions of a given pollutant. Here, for the subcategories of combustion turbines for which the EPA finds SCR is not cost-reasonable, the incremental $/ton values are well in excess of incremental cost values that have been deemed cost-effective in the past (see examples cited in section IV.B.3.c.i.).

For this category of sources, and in the context of conducting an NSPS review where the previous BSER was combustion controls, the EPA finds it particularly important to focus on the incremental $/ton of SCR rather than looking only at the total cost-effectiveness of an ''SCR with combustion control'' BSER as a whole. The SCR in this case is an additional control, to be combined with controls that are already widely used to comply with the current NSPS (and, indeed, largely built directly into most turbine models by the manufacturer). Failing to present or consider the incremental cost of SCR to the use of combustion controls alone would effectively mask the true driver of a large portion of the cost of a revised BSER that includes SCR.

In the case of combustion turbines, dry combustion controls are an inherent part of the affected facility and cannot be easily removed or modified and the end user has limited ability to change the way the combustion controls are operated. For turbines with wet combustion controls, if the water injection is turned off, thermal $NO_X$ would increase, but the increased combustion flame temperature and exhaust gas temperature potentially will result in damage to turbine components.

For this source category, it is generally the case that combustion turbine manufacturers have integrated combustion control technologies into the design of the turbine itself for decades, and turbines are sold with manufacturer guarantees of a specific level of $NO_X$ performance already built into the machine. Given that these controls are essentially priced into the retail cost of the turbine itself, it is difficult to generate reliable cost estimates for many types of combustion control technologies in isolation. Substantial improvements in $NO_X$ performance are readily achieved through combustion control technologies integrated into the turbine at the time of manufacture, and the cost of these controls is reflected in the price of purchase of the unit itself.

In contrast, SCR is an add-on technology that typically must be purchased separately and installed on-site, often through dedicated vendors and sub-contracts. The SCR is essentially an additional facility that must be constructed separately with its own footprint. As a practical matter, the costs associated with SCR are borne separately and are clearly additional to the costs of combustion controls. Further, combustion controls are now capable of achieving relatively low $NO_X$ emissions rates that approach what can be achieved with SCR. It makes sense to consider the incremental cost-effectiveness of a technology when that technology comes at substantially increased capital costs and operating and maintenance (O&M) costs over the life of its operation and, compared with a baseline level of emissions performance that is reflective of current or revised BSER determinations for combustion controls, only achieves modestly improved emissions performance compared to a far less costly technology.

The commenter also argues that SCR costs must be reasonable because many combustion turbines in recent years

[118] See Section II.A.1 of this preamble for further discussion of the case law under CAA section 111.

[119] *See* 62 FR 36948, 36955, 36958 (July 9, 1997).

[120] *See* 198 F.3d 930, 933.

[121] *See* 71 FR 9870 (Feb. 27, 2006).

[122] *See* Memorandum, $NO_X$ Control Technology Cost Per Ton for Stationary Combustion Turbines 7–8 (December 21, 2004), available at docket ID EPA–HQ–OAR–2004–0490–0114; Memorandum, Response to Public Comments on Proposed Standards of Performance for Stationary Combustion Turbines 53, available at docket ID EPA–HQ–OAR–0490–0322.

[123] *See, e.g.,* 89 FR 16820, 16864 (Mar. 8, 2024); 87 FR 35608, 35627 (June 10, 2022); 80 FR 64510, 64559 (Oct. 23, 2015); and 77 FR 56422, 56443 (Sept. 12, 2012). Citations to these examples are not intended to imply endorsement of the rules themselves, only that the Agency has had a consistent practice of looking at incremental costs in NSPS rulemakings.

have been required to install or have voluntarily installed SCR, citing to a variety of permitting decisions. The EPA agrees that SCR is generally an adequately demonstrated technology for combustion turbines. However, this commenter's argument collapses the statutory requirement that the Administrator find that a potential control technology is ''adequately demonstrated'' with the factors the Administrator must consider, including the cost of emissions reduction, when selecting the BSER. Many of the permitting decisions cited by the commenter lack meaningful or probative cost analysis with respect to SCR and focus instead on whether SCR is capable of being installed on the particular source at issue. In addition, many of the commenter's examples are for large high-utilization combined cycle turbines for which the EPA agrees that SCR is cost reasonable. However, the Agency disagrees that SCR is cost-reasonable for all subcategories on a nationwide basis, such that it must be included as part of the BSER for all combustion turbines. Whether SCR is cost-reasonable for smaller or lower utilization combustion turbines in particular permitting contexts is a determination that should continue to be made on a case-by-case basis by local and State permitting authorities, taking into consideration an array of localized factors, including air quality planning and NAAQS attainment status.[124]

d. Non-Air Quality Health and Environmental Impacts and Energy Requirements

Post-combustion SCR has several drawbacks compared to combustion controls technologies. SCR operation has associated ammonia emissions, a criteria pollutant precursor, reduces the output of the combustion turbine, and requires energy to operate. That auxiliary load energy is typically drawn from the combustion turbine itself, reducing the efficiency of its overall power generation and resulting in proportionally increased emissions of other air pollutants that result from combustion turbine operation.[125]

Post-combustion SCR uses ammonia as a reagent, and some ammonia is emitted either by passing through the catalyst bed without reacting with $NO_X$ (unreacted ammonia) or by passing around the catalyst bed through leaks in the seals. Both types of excess ammonia emissions are referred to as ''ammonia slip.'' Ammonia is a precursor to the formation of fine particulate matter (*i.e.,* $PM_{2.5}$). Ammonia slip typically increases as the catalyst beds age and is often limited to 10 ppm or less in operating permits. Ammonia catalysts, consisting of an additional catalyst bed after the SCR catalyst, reacts with the ammonia that passes through and around the catalyst to reduce overall ammonia slip. In the NETL model plants used in the EPA's analysis of SCR, no additional ammonia catalyst was included, and ammonia emissions were limited to 10 ppm at the end of the catalyst's service life. For estimating secondary impacts, the EPA assumed average ammonia emissions of 3.5 ppm. Assuming the ammonia slip is 3.5 ppm regardless of the $NO_X$ emissions rate prior to the SCR, the amount of ammonia emitted per ton of $NO_X$ controlled increases with combustion controls that achieve lower $NO_X$ emission rates prior to the SCR. For example, assuming the $NO_X$ emissions rate is decreased from the manufacturer guaranteed rate of 15 ppm to 3 ppm with the addition of SCR, the EPA estimates that for each ton of $NO_X$ controlled, 0.12 tons of ammonia will be emitted from SCR controls. For combustion turbines with guaranteed $NO_X$ emission rates of 9 ppm and 5 ppm, the EPA estimates the relative ammonia emissions increase to 0.33 tons and 0.65 tons of ammonia per ton of $NO_X$ controlled, respectively.[126] According to information submitted by commenters, ammonia slip increases as the percentage of $NO_X$ reduced by SCR increases above 80 percent. For example, the ammonia slip at 85 percent reduction is nearly double the ammonia slip at 80 percent reduction. And at 94 percent reduction, the ammonia slip is 10 times as high relative to 80 percent reduction.

Several commenters supportive of SCR technology called on the EPA to establish standards of performance for ammonia slip and took the view that this would be sufficient to mitigate this downside of SCR technology. First, as these and other comments acknowledged, ammonia slip is typically addressed through identifying facility-specific practices and conditions in the permitting process, and the EPA continues to view permitting as the appropriate mechanism for addressing this concern. Second, a standard of performance would still not eliminate ammonia emissions from SCR operation. Our analysis assumes ammonia emissions of 3.5 ppm, while these commenters called for setting an emissions limit of 2 ppm. Other commenters, however, stated that permitted ammonia emissions rates are often in the range of 7 to 10 ppm. In short, ammonia emissions of some level are a downside of SCR that at present cannot be entirely avoided, regardless of whether a limit is set, and it is reasonable to assume that such a hypothetical limit would be at or near the rate already assumed in our analysis.

The use of SCR also reduces the efficiency of a combustion turbine through the auxiliary/parasitic load requirements to run the SCR and the backpressure created from the catalyst bed. This not only reduces the net energy output of combustion turbines but also translates into increases in other types of emissions to the extent the turbine must run longer to produce the same amount of energy to meet energy requirements.[127]

In general, the EPA does not believe that these effects, on their own, exclude SCR from being part of the BSER. However, these impacts are sufficiently adverse that, in the case of minimal incremental $NO_X$ reductions from SCR as compared with combustion controls alone, they support a conclusion that SCR is not part of the BSER. Thus, the non-air quality health and environmental impacts and energy requirements of SCR support the conclusion that SCR does not qualify as the BSER for turbines with combustion controls capable of achieving 5 ppm $NO_X$. For combined cycle turbines using less effective combustion controls, the non-air quality and environmental impacts do not necessarily eliminate SCR as the BSER, and these effects do not change our determination that SCR is part of the BSER for large high-utilization combustion turbines. With respect to the low-utilization and small and medium combustion turbines for which the EPA identifies a range of cost-

[124] The EPA further notes that the analysis required in promulgating or reviewing an NSPS is materially different than the analysis required for permitting. For example, CAA section 111(b)(2) authorizes the Agency to distinguish only among classes, types, and sizes of new sources, whereas permitting decisions focus on particular sources in a facility-specific way. 42 U.S.C. 7411(b)(2).

[125] Note that in this section we evaluate a range of environmental impacts associated with SCRs. To the extent these impacts are not explicitly covered under the ''nonair quality health and environmental impact'' factor, they are nonetheless statutorily relevant in identifying the ''best'' system of emissions reduction. *See* section II.A.1 of this preamble.

[126] Ammonia has a lower molecular weight (17) than $NO_2$ (46). Thus, although more molecules of ammonia are being emitted in the example of a combustion turbine with a guaranteed $NO_X$ emissions rate of 5 ppm, the mass of $NO_X$ is greater.

[127] Among the pollutants that would potentially increase in association with this increase in operation is formaldehyde, a hazardous air pollutant regulated for combustion turbines at major sources under CAA section 112. *See generally* 40 CFR part 63, subpart YYYY.

effectiveness values for SCR, the lower ends of which may be considered reasonable at least under some scenarios, the EPA finds these downsides to SCR are sufficient to tip the scale away from including SCR in the BSER.

Some commenters asserted that SCR, when used in combination with combustion controls, is clearly the BSER even if it has downsides under some BSER factors. These commenters asserted that statutory language and case law requires the EPA to prioritize and maximize emissions reductions.

The EPA agrees with the commenter that adequately demonstrated technologies that achieve the greatest amount of emissions reduction need to be carefully considered under all the BSER factors. However, the statutory language does not bear out the commenters' claim that the EPA must always mandate the most emissions reductions possible through our BSER determinations, heedless of the other statutory factors Congress directed the Agency to consider in CAA section 111(a)(1). In general, the courts have recognized that the EPA has considerable discretion in weighing those factors,[128] and a general policy of selecting the technology with the greatest emissions reductions irrespective of the ''cost of achieving such reduction,'' ''nonair quality health and environmental impact[s],'' and ''energy requirements'' would be inconsistent with the statute.[129]

Here, the analyses above supply important and persuasive information that SCR is not the BSER for many types of combustion turbine applications for cost and other reasons. If the Agency were to follow the approach suggested by some commenters and include a stringent standard of performance across the board for combustion turbines that could only be met with SCR, it could discourage the development of other control technologies that do not suffer from similar drawbacks and would likely increase emissions of other pollutants.[130] For example, a BSER that includes SCR could substantially reduce the incentive to improve combustion control design and performance. Once SCR is installed on a unit, the type of combustion control used matters less. Taking ammonia costs as an example, while less ammonia is required and those costs are reduced with improved combustion controls in combination with SCR, the savings are small relative to the overall annual costs of SCR. All else being equal, the annual SCR costs for a 50 MW simple cycle turbine with a 15 ppm $NO_X$ guarantee is 0.9 percent lower than for a turbine with a 25 ppm $NO_X$ guarantee (an annual savings of $6,000).[131] Similarly, the annual costs of a turbine with a 9 ppm $NO_X$ guarantee are 0.7 percent ($5,000) lower than a comparable turbine with a 15 ppm $NO_X$ guarantee. These incremental reductions in SCR costs are relatively low and not likely to offer a competitive advantage for an end user purchasing a turbine with combustion controls with lower guaranteed $NO_X$ emission rates. The economic incentive for manufacturers to invest in improved combustion controls is to gain a competitive advantage by developing turbines that do not require SCR, at least in certain situations. If a BSER determination is made that effectively mandates SCR for all new combustion turbines, regardless of the level of emissions reduction achieved with combustion controls, there would be little incentive for manufacturers to invest in improved combustion controls. This could lead to increased costs for users of energy, increased fuel use (from the efficiency loss associated with SCR), and increased ammonia emissions.

Other commenters stated in response to the proposed rule that the EPA should exclude SCR as a component of the BSER for large combustion turbines utilized at lower capacity factors because the proposed SCR costs, as well as the proposed 3 ppm $NO_X$ standards for large simple cycle turbines that result from including SCR in the BSER, are arbitrary and unreasonable. Instead, according to the commenters, the BSER for these large turbines should be advanced DLN or DLN combustion controls with associated $NO_X$ emission limits, as appropriate. The commenters argued that the proposed determination of the BSER did not consider the full costs of adding SCR to larger simple cycle turbines (*i.e.,* those greater than 850 MMBtu/h). Specifically, the hot exhaust gases require cooling prior to the SCR, resulting in an approximate doubling of capital costs. Such costs would cause an entire class of larger frame-type turbines to be eliminated from consideration for use due to cost. According to two commenters, large turbines have guaranteed $NO_X$ emission rates ranging from 5 ppm to 25 ppm by utilizing only combustion controls. The commenters added that the exclusion of SCR as the BSER for these turbines would support the creation of additional subcategories for combustion turbines with base load rated heat inputs greater than 850 MMBtu/h.

Based on a review of comments, the EPA is not including in subpart KKKKa the proposed subcategory for all sizes of new and reconstructed combustion turbines that would operate at intermediate loads (*i.e.,* at 12-calendar-month capacity factors greater than 20 percent and less than or equal to 40 percent). The EPA is also determining in subpart KKKKa that SCR does not qualify as the BSER for large low-utilization combustion turbines (*i.e.,* with 12-calendar-month utilization levels less than or equal to 45 percent). Instead, the EPA is determining that the BSER is the use of combustion controls for all sizes of new low-utilization combustion turbines. These changes address commenters' concerns about being required to install SCR for simple cycle turbines, which, as discussed in section IV.B.2, have not historically operated at high utilization levels. For large high-utilization combustion turbines, including simple cycle turbines, the BSER includes the use of SCR as proposed, for the reasons discussed above.

4. Evaluation of Combustion Controls Under BSER Factors

Since proposal, the EPA has undertaken a careful review of the BSER criteria in relation to combustion controls and has considered the extensive technical comments submitted. This includes information about the availability and performance of wet combustion controls (*i.e.,* steam or water injection), dry combustion controls, and the performance of advanced combustion controls for certain types and classes of available stationary combustion turbines. Advanced combustion controls generally refer to dry combustion controls that have been tuned, upgraded, or modified to improve the combustion process in such a manner as to limit the formation of thermal $NO_X$. These include technologies such as lean premixed combustion, DLN and ultra DLN burners, staged combustion, and flue gas recirculation, which generally

[128] *See, e.g., Sierra Club* v. *Costle,* 657 F.2d 298, 346–47 (D.C. Cir. 1981).

[129] 42 U.S.C. 7411(a)(1).

[130] *See id.* (''We have no reason to believe Congress meant to foreclose in section 111(a) any consideration by EPA of the stimulation of technologies that promise significant cost, energy, nonair health and environmental benefits. . . . [W]hen balancing the enumerated factors to determine the basic standard it is appropriate to consider which level of required control will encourage or preclude development of a technology that promises significant advantages with respect to those concerns.'').

[131] These costs are derived using the EPA's cost model as proposed and without adjusting based on the information provided by commenters intended to demonstrate that the EPA's estimated capital costs of SCR for simple cycle turbine are low. Using higher capital costs would reduce the percent reduction in savings from improved combustion controls.

result in lower $NO_X$ emission rates than non-advanced combustion controls.[132]

The basis of dry combustion control or DLN combustion control is to premix the fuel and air and supply the combustion zone with a homogenous, lean mixture of fuel and air. Lean premix means the air-to-fuel ratio contains a low quantity of fuel, and the DLN combustors in the turbine are designed to sustain ignition of this lean premix air/fuel mixture at a lower peak flame temperature, thereby limiting the formation of thermal $NO_X$. Lean combustion may be combined with staged combustion to achieve additional $NO_X$ reductions. Staged combustion is designed to reduce the residence time of the combustion air in the presence of the flame at peak temperature. The longer the residence time, the greater the potential for thermal $NO_X$ formation. When increasing the air/fuel ratio, excess air is added to the mixture, which both leans the combustion air by adding more air to the air/fuel ratio and decreases the residence time at peak flame temperatures.

Wet combustion controls involve the injection of water (or steam) into the flame area of the combustion reaction to reduce the peak flame temperature in the combustion zone and limit thermal $NO_X$ formation.[133] Wet control systems are designed to a specific water-to-fuel ratio that has a direct impact on the controlled $NO_X$ emission rate and is generally controlled by the combustion turbine inlet temperature and ambient temperature. Water injection also increases the mass flow rate and the power output, but the energy required to vaporize the water can reduce overall efficiency.

Steam injection is like water injection, except that steam is injected into the compressor and/or through the fuel nozzles directly into the combustion chamber instead of water. Steam injection reduces $NO_X$ emissions and has the advantage of improved efficiency and larger increases in the output of the combustion turbine. When compared to standard simple cycle turbines, combustion turbines using steam injection are more efficient but more complex with higher capital costs. Conversely, compared to standard combined cycle combustion turbines, the combustion turbines using steam injection are simpler and have shorter construction times and lower capital costs but also lower efficiencies.[134] Combustion turbines using steam injection can start quickly, have good part-load performance, and can respond to rapid changes in demand. Since the exhaust gas is cooled, it reduces or eliminates the need for air tempering prior to any associated SCR and thereby lowers the costs of SCR.

The EPA is determining that combustion controls continue to be either the BSER or part of the BSER for all subcategories of new, modified, or reconstructed stationary combustion turbines in subpart KKKKa. This is the result of a revised BSER analysis since proposal that supports the conclusion that combustion controls alone, without the addition of SCR, are the BSER for all but one subcategory of new stationary combustion turbines and for all modified or reconstructed turbines.

The different types of dry combustion controls have been standard equipment on stationary combustion turbines for decades and have been shown to be cost-effective while achieving substantial reductions in $NO_X$. Furthermore, the technology has continued to improve, as demonstrated by the lower guaranteed $NO_X$ emission rates of advanced combustion controls for certain sizes, classes, and types of new turbines compared to the performance of combustion controls that were available when subpart KKKK was promulgated in 2006. For certain classes of turbines, advanced combustion controls with DLN or ultra DLN have demonstrated the ability to achieve $NO_X$ emission rates comparable to the $NO_X$ emission rates achieved by combustion turbines that operate with SCR but at lower cost and without the drawbacks of SCR discussed elsewhere in this preamble.

Wet combustion controls (including steam-injection), by contrast, are also a mature combustion control technology but generally there have not been significant improvements in emissions performance with these technologies over time. Wet combustion controls remain the appropriate control type for non-gaseous fuels. However, in general, for natural gas-fired combustion turbines, the EPA bases its BSER determinations and emissions standards on dry combustion controls. Nonetheless, this preamble also discusses circumstances in which wet controls may be able to meet the selected emissions standards for certain subcategories firing natural gas.

Based on the EPA's revised analysis, the BSER for most subcategories of new, modified, and reconstructed combustion turbines subject to subpart KKKKa is the use of wet, dry, or advanced dry combustion controls alone (*i.e.,* without SCR).

a. Adequately Demonstrated

Combustion controls were determined to be the BSER in subpart KKKK and continue to be widely used as $NO_X$ emission controls on new stationary combustion turbines.[135] In that sense, combustion controls can be considered to be ''adequately demonstrated''; however, after considering all of the BSER factors as described in the sections that follow, the EPA finds that different types of combustion controls have varying degrees of feasibility and emissions performance in relation to specific combustion turbine applications. Thus, in generally finding that combustion controls are an ''adequately demonstrated'' technology for the source category, the EPA does not mean to imply that the most stringent combustion control technologies necessarily qualify as the BSER for all subcategories of combustion turbines. The various combustion control technologies and our evaluation of them under the BSER factors are further discussed in this and the sections that follow.

Combustion control systems were commercially introduced more than 30 years ago and consist of operational or design modifications that govern combustion conditions to reduce $NO_X$ formation. The control technology is widely available from major manufacturers of natural gas-fired aeroderivative and frame type stationary combustion turbines and is a mature technology that has been demonstrated in various end-use applications.[136] In

[132] Unless otherwise indicated, ''combustion controls'' is used in this preamble as an umbrella term to refer to both combustion controls and advanced combustion controls. Advanced combustion controls have guaranteed emission rates of less than 25 ppm $NO_X$.

[133] In general, the addition of water or steam will not increase emissions of carbon monoxide (CO) or unburned hydrocarbons. However, at higher injection rates, emissions of CO and unburned hydrocarbons can increase.

[134] Bahrami, S., et al (2015), *Performance Comparison between Steam Injected Gas Turbine and Combined Cycle during Frequency Drops.* Energies 2015, Volume 8. Accessed at *https://doi.org/10.3390/en8087582;* Mitsubishi Power, *Smart-AHAT (Advanced Humid Air Turbine.* Accessed at *https://power.mhi.com/products/gasturbines/technology/smart-ahat.*)

[135] *See* 71 FR 38482 (July 6, 2006).

[136] Combustion turbine manufacturers publish information about their products, including the different combustion controls for each model of combustion turbine commercially available. This includes combustion turbine size, rated output, emission controls, and guaranteed $NO_X$ emission rates. This information is also summarized in the combustion turbine specification sheet included in the docket for this rulemaking (Docket ID: EPA–HQ–OAR–2024–0419); *See also* Siemens gas turbines at *https://www.siemens-energy.com/global/en/home/products-services/product-offerings/gas-turbines.html;* GE/Vernova gas turbines at *https://www.gevernova.com/gas-power/products/gas-turbines;* Mitsubishi Power gas turbines at *https://*

Continued

subpart KKKKa, the EPA maintains that combustion controls are, as a general matter, adequately demonstrated for new, modified, or reconstructed natural gas-fired turbines of all sizes. However, the availability of dry combustion controls that can achieve a particular guaranteed $NO_X$ emission rate (*e.g.,* 25 ppm, 15 ppm, 9 ppm, and 5 ppm) varies between the subcategories and applications. The availability of more advanced combustion controls that can achieve $NO_X$ emission rates less than 25 ppm tends to correlate with turbine size. For example, according to turbine manufacturer specifications and information in *Gas Turbine World,* most models of combustion turbines with guaranteed $NO_X$ emission rates of 9 ppm would fall within the large turbine subcategory, whereas the availability of 9 ppm $NO_X$ turbines is generally more limited in the medium and small subcategories. Similarly, as discussed in section IV.B.2.c of this preamble, dry combustion controls can achieve differing $NO_X$ emission rates depending in part on the efficiency of the turbine model to which they are applied. Thus, the EPA is determining that combustion controls with different guaranteed $NO_X$ emission rates are adequately demonstrated for different subcategories of combustion turbines, based primarily on the current state of development of those controls as evidenced by availability of turbines of different sizes and efficiencies that meet certain guaranteed $NO_X$ emission rates.

Specifically, for the subcategory of large low-utilization combustion turbines, the EPA finds that advanced combustion controls that have guaranteed $NO_X$ emission rates of 9 ppm are adequately demonstrated for less efficient turbine designs. For large low-utilization combustion turbines with higher efficiencies, advanced combustion control technologies are not as effective, *i.e.,* cannot achieve the same emission rates due to the higher combustion temperatures necessary for increased efficiency. Therefore, based on the capabilities of controls available for such turbines, the EPA finds that advanced combustion controls with guaranteed $NO_X$ emission rates lower than 25 ppm are not adequately demonstrated for these higher efficiency turbine models, whereas dry combustion controls with guaranteed rates of 25 ppm *are* adequately demonstrated for this subcategory of large low-utilization combustion turbines.

The subcategories of medium combustion turbines include many models of combustion turbines designed to be operated at higher levels of utilization. For these applications and turbines sizes, dry combustion controls have manufacturer guaranteed $NO_X$ emission rates of 15 ppm, and the EPA is determining that such controls are adequately demonstrated for medium high-utilization combustion turbines. For many models of medium combustion turbines designed to be operated at lower levels of utilization, both wet and dry combustion controls achieve the same manufacturer guaranteed emission rate of 25 ppm $NO_X$. Wet combustion controls have particular benefits for medium turbines operating at approximately 20 percent annual utilization or less, while at utilizations of 20 to 40 percent, dry combustion controls are more cost effective. However, as stated above, both wet and dry combustion controls achieve the same $NO_X$ emission rate for combustion turbines in the medium low-utilization subcategory and both are adequately demonstrated.

While some small combustion turbines can be equipped with advanced combustion controls with guaranteed $NO_X$ emission rates of less than 25 ppm, such controls are not widely available across the entire subcategory. Therefore, the EPA has determined that such advanced combustion controls have not been adequately demonstrated for the small combustion turbine subcategory. Based on information from turbine manufacturers and commenters, the EPA determines combustion controls, both wet and dry, with guaranteed $NO_X$ emission rates of 25 ppm are adequately demonstrated for all small combustion turbines.

For new turbines that burn non-natural gas fuels (*e.g.,* distillate oil), the EPA maintains that wet combustion controls only are adequately demonstrated for control of $NO_X$ emissions. *I.e.,* dry combustion controls are not adequately demonstrated for such turbines because, as discussed in sections IV.B.2.d and IV.7.a of this preamble, dry combustion controls have limited applicability to limit $NO_X$ emissions when liquid fuels are fired. Wet combustion controls (*e.g.,* water or steam injection) are a mature combustion control technology that has been used since the 1970s to control $NO_X$ emissions from combustion turbines. As discussed above, the EPA also maintains that wet combustion controls are available for certain natural gas-fired combustion turbines as an alternative to dry combustion controls. The emission standards for small and medium turbines in subpart KKKK could be achieved using either wet or dry combustion controls. However, wet combustion controls were not part of the BSER for large natural gas-fired combustion turbines in subpart KKKK because the technology had not demonstrated the ability to achieve $NO_X$ emissions rates of less than 25 ppm.[137]

b. Extent of Reductions in $NO_X$ Emissions

Combustion turbines without $NO_X$ controls use combustors that are diffusion controlled where fuel and air are injected separately. The resultant diffusion flame combustion can lead to the creation of hot spots that produce high levels of thermal $NO_X$—as high as 200 ppm. Combustion controls are widely available for new combustion turbines and provide substantial reductions in $NO_X$ emissions relative to combustion turbines without combustion controls.

The level of $NO_X$ reduction that can be achieved with dry combustion controls depends on the combustion systems that have been developed for the specific turbine product line. Development of dry combustion systems is a research intensive and expensive undertaking that is specific to each turbine product line (*i.e.,* combustors developed for a specific turbine model cannot be used on a different turbine model). While almost all combustion systems developed by manufacturers and third parties can achieve 25 ppm $NO_X$ when burning natural gas, some combustion systems with more advanced technologies can achieve 15 ppm, 9 ppm, or 5 ppm $NO_X$. The feasibility of lower $NO_X$ emissions is additionally impacted by the characteristics of the turbine. For example, compact turbines that can start and stop quickly (typical of aeroderivative turbines) and turbines with high firing temperatures (typical of higher efficiency turbines) have emission guarantees of 25 ppm $NO_X$. And turbines that are physically larger on a per MW of output basis, and turbines with lower firing temperatures, frequently have available combustion systems with emission guarantees of 15 ppm $NO_X$ or less. The operating parameters that influence guaranteed $NO_X$ emission rates include turbine load, fuel, and ambient conditions, which are like the parameters used to determine the applicable hourly emissions standards in this final rule, meaning that the EPA's BSER determinations and standards reflect the

*power.mhi.com/products/gasturbines;* and Solar Turbines at *https://www.solarturbines.com/en_US/products.html.*

[137] The emissions standard in subpart KKKK for large natural gas-fired turbines is 15 ppm $NO_X$.

real-world conditions in which turbines will be operating. Based on emissions information reported to CAMPD, these guaranteed emission rates are being achieved in practice. For all these reasons, the EPA has determined that it is appropriate to use manufacturer guarantees for the purposes of assessing the extent of $NO_X$ emission reductions for the BSER analysis, as well as for establishing emission standards in subpart KKKKa.

Wet control systems are simpler to implement and have demonstrated the ability to limit $NO_X$ emissions to as low as 25 ppm for stationary combustion turbines firing natural gas and between 42 ppm and 74 ppm for sources firing non-natural gas fuels. The EPA is not aware of any advances in combustion controls for non-natural gas-fired fuels relative to the analysis it conducted for subpart KKKK in 2006.

c. Costs

The EPA initially assessed costs relative to a starting point of a combustion turbine with a base load rating of less than 850 MMBtu/h of heat input using combustion controls with a $NO_X$ emissions rate guarantee of 25 ppm, and a guarantee of 15 ppm $NO_X$ for a turbine with a base load rating greater than 850 MMBtu/h of heat input. These are appropriate initial baselines because, absent the revisions to the NSPS being finalized in this action, they are the standards to which natural gas-fired combustion turbines are subject under subpart KKKK. Thus, in this rulemaking, the EPA is assessing incremental costs associated with revising the existing $NO_X$ standards.

Importantly, the EPA believes that the costs of combustion controls are reasonable for the source category because turbine manufacturers are currently making, and end users (including in the utility, industrial, and institutional sectors) are currently purchasing and operating, combustion turbines with guaranteed $NO_X$ emission rates of 25 ppm, 15 ppm, and 9 ppm.[138] In general, due to more complex combustion systems (*e.g.,* additional fuel nozzles and burners, premixing larger amounts of air with the fuel, and more sophisticated control systems) and/or maintenance requirements, costs increase as the guaranteed $NO_X$ emissions rate of a combustion turbine decreases. Moreover, assessing the incremental costs of combustion controls is different from assessing the costs of other, add-on pollution controls because combustion controls are integrated into the up-front design and manufacture of combustion turbines. It can therefore be difficult to disentangle the costs of the controls from the costs of the turbines themselves. The EPA has endeavored to do so, but this cost analysis of combustion controls relies more heavily on the overall availability and costs of different sizes, classes, *etc.,* of turbines and their associated controls, as well as the current use of specific types of turbines in specific applications, as indicators of cost reasonableness than might be appropriate in other contexts.

As stated above, the fact that turbines with combustion controls guaranteeing $NO_X$ emission rates ranging from 9 ppm to 25 ppm are being purchased and used today is an indicator that the incremental capital and operating costs of combustion controls (including advanced combustion controls) relative to diffusion flame turbines are reasonable.[139] However, the characteristics of how a turbine is operated can impact the cost effectiveness of combustion controls. For example, if a unit is operating less it will emit less $NO_X$, while the capital cost of the combustion controls remains relatively unaffected. As a result, all else being held equal, the cost per ton of $NO_X$ reduced increases as utilization decreases. Therefore, while the capital costs of combustion controls are generally reasonable for the source category, for certain subcategories of combustion turbines, the cost *effectiveness* of certain combustion controls to meet particular guaranteed $NO_X$ emission rates may not be.

In the 2024 proposed rule, the Agency solicited comment on detailed capital and O&M cost information and other impacts for combustion turbines with $NO_X$ guarantees of 15 ppm, 9 ppm and 5 ppm relative to the costs of comparable combustion turbines with 25 ppm $NO_X$ guarantees. The EPA stated in the proposal that to the extent the Agency received information that the costs of more advanced combustion controls are reasonable, $NO_X$ emission standards consistent with these guaranteed levels could be finalized.[140]

In response, commenters did not provide significant additional information on the incremental cost impacts of combustion controls with different guaranteed $NO_X$ emission rates (*i.e.,* on the differences in costs between 25 ppm, 15 ppm, 9 ppm, and 5 ppm combustion systems, respectively); however, they did provide information on the cost of combustion controls capable of achieving 25 ppm $NO_X$ emissions relative to diffusion flame combustion. According to commenters' information, adding dry combustion controls increased the capital costs relative to a comparable combustion turbine using diffusion flame combustion but the efficiency and operating costs for turbines were unaffected by controlling emissions to 25 ppm $NO_X$.[141] In contrast, the EPA's estimates of incremental emissions reductions from combustion systems capable of achieving 15 ppm and 9 ppm $NO_X$ relative to a 25 ppm $NO_X$ combustion system include capital costs as well as efficiency and operating costs of controls. This indicates that the EPA's estimated impacts of the incremental costs and efficiency impacts of improvements in combustion controls may be conservatively high.

In evaluating the costs and cost reasonableness of different types of combustion controls, the EPA considered the applications for which turbines in different subcategories are designed and the corresponding ways in which they are operated. Small- and medium-sized turbines that operate at low levels of utilization include, but are not limited to, peaking turbines, which are often simple cycle turbines used to provide power during peak summer demand when ambient temperatures are high. They also include turbines that are not, strictly speaking, peaking turbines but that operate 40 percent of the time or less on an annual basis. For both types of turbines (*i.e.,* peaking turbines and other low-utilization turbines), wet and dry combustion controls that achieve a $NO_X$ emission rate of 25 ppm are adequately demonstrated. Thus, for the purposes of these revisions to subpart KKKKa, the EPA estimated the costs of wet combustion controls at 25 ppm $NO_X$ compared to dry combustion controls at 25 ppm $NO_X$. Although wet combustion controls are sometimes less effective at reducing emissions than dry combustion controls, the use of wet combustion controls increases the design output of simple cycle turbines and can reduce capacity and efficiency losses because of high ambient

[138] *See* the inventory in the docket of turbines that have recently commenced operation in the U.S.

[139] As discussed in section IV.B.4.a of this preamble, while combustion controls are broadly available for and used in the source category, advanced combustion controls are currently less available for smaller turbine sizes and are not available for large, high-efficiency turbines. As a corollary to their lack of general availability for such turbines, advanced combustion controls would also de facto not be cost reasonable for small and large, high-efficiency turbines.

[140] *See* 89 FR at 101328, 101331, 101333 (requesting information on, among other things, the capital and O&M costs of combustion controls to meet varying emission rates for small, medium, and large combustion turbines).

[141] *See* the Electric Power Research Institute (EPRI) supporting materials.

temperatures relative to the use of dry combustion controls. Wet combustion controls also have lower capital costs than dry combustion controls. However, wet combustion controls require highly purified water and reduce the turbine efficiency, which contributes to higher operating costs relative to the sue of dry combustion controls. Based on information provided by commenters, at a $NO_X$ emissions standard of 25 ppm, the use of wet combustion controls results in lower overall costs than the use of dry combustion controls, but only up to a utilization rate of approximately 20 percent, which is consistent with a turbine that is operated in peaking applications.[142] The costs of dry combustion controls at these relatively low rates of utilization would be higher.[143] For annual utilization rates above 20 percent, dry combustion controls are generally more cost reasonable than wet combustion controls. Given that the low-utilization subcategory for medium combustion turbines encompasses both of these applications—peaking turbines at the lowest end of the utilization spectrum and turbines that operate more frequently but still below 40 percent annual utilization—and that both wet and dry combustion controls for turbines with these characteristics achieve 25 ppm $NO_X$, the EPA is determining that the costs of combustion controls that can meet this emission rate, whether wet or dry, are reasonable.

Notwithstanding the preceding analysis of and conclusions about the costs of wet and dry combustion controls that achieve 25 ppm $NO_X$ for certain small and medium turbines, the EPA also evaluated the costs of advanced combustion controls for all sizes of combustion turbines (*i.e.,* including small and medium turbines). For medium and small turbines with combustion systems with emission guarantees of less than 25 ppm $NO_X$, most are 15 ppm $NO_X$ turbines with the availability of 9 ppm $NO_X$ turbines being more limited. Since combustion turbines with 9 ppm $NO_X$ are not widely available within the medium and small turbines subcategories, the EPA is not considering combustion controls with 9 ppm $NO_X$ guarantees as a potential BSER for these subcategories.

To estimate the costs of advanced dry combustion controls capable of achieving 15 ppm $NO_X$, relative to a turbine with a combustion system capable of achieving 25 ppm $NO_X$, the EPA used three costing models.[144] The first reduced the efficiency of the combustion turbine and the corresponding output by 2 percent while leaving everything else constant. The second approach is based on available information for an aeroderivative turbine with multiple combustion system options and reduced the heat rate, output, and variable costs of the lower $NO_X$ turbine. The third assumed an increase in capital costs of the turbine with lower $NO_X$ emission rates but similar performance.[145]

For medium low-utilization turbines operating at a capacity factor of 9 percent, the cost effectiveness of advanced combustion controls with 15 ppm $NO_X$ guarantees ranges from $22,000/ton to $46,000/ton $NO_X$ abated.[146] The EPA does not consider these costs reasonable and therefore, based on both the preceding analysis of wet and dry combustion controls that achieve 25 ppm $NO_X$ for medium low-utilization turbines and the high cost-per-ton figures here, the Agency is determining that the use of combustion controls capable of achieving 15 ppm $NO_X$ does not qualify as the BSER for medium low-utilization turbines. Due to economies of scale, the incremental control costs would be even higher for small turbines relative to those for medium turbines. Therefore, the Agency also does not consider the use of combustion controls capable of achieving 15 ppm $NO_X$ as the BSER for small low-utilization turbines.[147] However, at a utilization level of 40 percent, the cost effectiveness of combustion controls for medium turbines is $8,000/ton to $10,000/ton $NO_X$ abated. Considering that this is likely an overestimate and that there are limited, if any, secondary environmental impacts, the EPA considers these costs reasonable, and the use of combustion controls with guaranteed emission rates of 15 ppm $NO_X$ could qualify as the BSER for medium high-utilization turbines. The incremental control costs of more advanced combustion controls for small turbines are higher than for medium turbines and, although the costs may appear reasonable before considering cost adjustments as discussed in section IV.B.4.a of this preamble, the EPA has determined that small turbines with 15 ppm $NO_X$ guarantees are not available across the entire subcategory and therefore do not qualify as the BSER.

As explained in sections IV.B.3 and IV.B.5 of this preamble, the EPA is determining that the BSER for large high-utilization turbines of any efficiency is combustion controls with SCR. Further, as discussed in section IV.B.4.a of this preamble, advanced combustion controls are not adequately demonstrated for large, higher efficiency combustion turbines operating at lower levels of utilization. Therefore, the EPA's cost analysis of advanced combustion controls for large turbines focuses on low-utilization, lower efficiency combustion turbines.

For large low-utilization, lower efficiency combustion turbines, the EPA considered advanced combustion controls that can achieve $NO_X$ emission rates of 9 ppm. At a capacity factor of 9 percent, the cost effectiveness of combustion controls for large turbines with 9 ppm $NO_X$ guarantees ranges from $15,000/ton to $33,000/ton $NO_X$ abated relative to a baseline of 15 ppm $NO_X$. The Agency reviewed the design information in *Gas Turbine World* to assess the impacts on turbine performance of advanced combustion controls to achieve $NO_X$ guarantees of 9 ppm versus 15 ppm. This assessment revealed that, when accounting for size (which the Agency did not do at proposal), there was no significant difference in performance between

[142] This does not account for potential financial benefits of certain wet combustion controls (*e.g.,* inlet fogging and wet compression used in combination with direct injection of water into the combustor or steam injection) reducing the efficiency and output losses that result from high ambient temperatures. However, given that the cutoff for the low utilization subcategory is 40 percent and that, below this threshold, both dry and wet combustion controls are reasonable under various circumstances and regardless can achieve the same $NO_X$ emission rate, we did not find it necessary to further account for these potential benefits.

[143] *See* the Electric Power Research Institute (EPRI) supporting materials.

[144] *See* the $NO_X$ control technology technical support document included in the docket for this rulemaking.

[145] The costs of advanced DLN may be approximately $24/kW (2024$). *See Control Technologies Review for Gas Turbines in Simple, Combined Cycle and Cogeneration Systems,* Eastern Research Group, Inc., September 1, 2014. The third costing model may be more relevant to frame type turbine because the size of the combustor is less of an issue relative to aeroderivative turbines. Other sources report the costs of advanced DLN as approximately $2.6/kW. *See Cost Analysis of $NO_X$ Control Alternatives for Stationary Gas Turbines.* Onsite Sycom Energy Corporation. November 5, 1999.

[146] For the medium low-utilization subcategory, most affected facilities will use simple cycle turbines. The EPA has already determined that wet combustion controls have not been demonstrated to be able to achieve 15 ppm $NO_X$ and these costs are shown for completeness. Even if the costs were reasonable the Agency would not necessarily determine the dry combustion controls with emission guarantees of 15 ppm $NO_X$ is the BSER for the low-utilization medium turbine subcategory or the small turbine subcategory.

[147] Even if the incremental control costs of more advanced combustion controls for small turbines were reasonable, as discussed in section IV.B.4.a, the EPA has determined that small turbines with 15 ppm $NO_X$ guarantees are not available across the entire subcategory and therefore would not qualify as the BSER.

turbines with 15 ppm and 9 ppm $NO_X$ guarantees (at proposal, the EPA estimated a 2 percent increase in heat rate). In addition, within the large low-utilization, lower efficiency combustion turbine subcategory (large low-utilization turbines with design efficiencies of less than 38 percent), most new turbines have emission guarantees of 9 ppm $NO_X$ or less. Due to the similar design performance characteristics of large turbines with 15 ppm and 9 ppm $NO_X$ emission guarantees, and that most of the large lower efficiency combustion turbines available have $NO_X$ emission guarantees of 9 ppm, for the purposes of this analysis, the Agency is assuming that the costs and performance of large lower efficiency turbines are similar regardless of whether the $NO_X$ emissions guarantee is 15 ppm or 9 ppm. Therefore, the incremental costs of amending the $NO_X$ emissions standard for large low-utilization, lower efficiency combustion turbines from 15 ppm to 9 ppm is minimal. Furthermore, relative to a baseline of 25 ppm $NO_X$, the cost effectiveness ranges from $8,000/ton to $17,000/ton. The EPA has determined that the cost effectiveness values are likely on the low end of this range, $8,000/ton. The EPA considers these costs reasonable. Therefore, it is not appropriate to amend the standard to 25 ppm $NO_X$. Moreover, the EPA estimates that the incremental costs of a BSER based on the use of advanced combustion controls guaranteed at 9 ppm $NO_X$ relative to advanced combustion controls guaranteed to achieve 15 ppm $NO_X$ likely does not represent a significant cost and could qualify as the BSER, at least for the large low-utilization turbine subcategory.[148]

d. Non-Air Quality Health and Environmental Impacts and Energy Requirements[149]

Due to the potential efficiency loss of a combustion turbine with $NO_X$ guarantees of 15 ppm and 9 ppm relative to a combustion turbine with $NO_X$ guarantees of 25 ppm, for each ton of $NO_X$ reduced, additional emissions may be generated. This reduction in efficiency is in the combustion turbine engine and at least a portion of the lost turbine engine efficiency can be partially recovered in the HRSG of combined cycle and CHP facilities. If emission rates of other pollutants are unchanged by the low-$NO_X$ combustor, the loss of efficiency would mean that emissions of other criteria and hazardous air pollutants (HAP) would increase by a maximum of approximately 2 percent. However, as noted previously, the efficiency differences between large turbines with 15 ppm $NO_X$ and 9 ppm $NO_X$ guarantees is negligible and actual reductions in efficiency may be less.

In general, the EPA finds that the non-air quality health and environmental impacts and energy requirements of both dry and wet combustion controls are acceptable, whether in conjunction with controls capable of meeting 25 ppm, 15 ppm, 9 ppm, or 5 ppm $NO_X$ emission standards when firing natural gas.

5. Revised NSPS for Stationary Combustion Turbines

The following sections describe the EPA's determinations of the BSER and the degree of $NO_X$ emission limitation achievable through application of the BSER for each subcategory of stationary combustion turbine in subpart KKKKa. These determinations are based on the results of a technology review of demonstrated $NO_X$ emission controls, including information received during the public comment period. The following sections describe each of the combustion turbine subcategories, each BSER technology determination, and the associated $NO_X$ standards of performance in subpart KKKKa.

The control technologies the EPA evaluated for each size-based subcategory, whether the combustion turbine is utilized at a high or low rate on a 12-calendar-month basis, whether the combustion turbine is more or less efficient, whether the combustion turbine burns natural gas or non-natural gas fuels, or whether the combustion turbine is operated at full or part loads on an hourly basis, include dry combustion controls (*i.e.,* lean premix/DLN), wet combustion controls (*i.e.,* water or steam injection) (together, ''combustion controls''), and post-combustion SCR.[150]

The EPA used three primary sources of information for determining appropriate emission standards—combustion turbine manufacturer guaranteed $NO_X$ emission rates, information provided in public comments, and hourly emissions database information reported to the EPA and available from CAMPD. The EPA considered, but did not use, permitted emission rates (*i.e.,* emission rates included in permits to construct or operate) because the numeric standards differ in terms of the averaging period used for compliance purposes and the operating conditions under which the standards are applicable. Similarly, the EPA did not base the $NO_X$ emission standards on stack performance test information because these emission rates are representative of what can be achieved under the conditions of a performance test and do not necessarily represent what is achievable under other operating conditions. Therefore, the EPA determines that manufacturer guarantees represent appropriate $NO_X$ emission standards for determination of the BSER based on the use combustion controls. The EPA also determines that the analysis of hourly emissions data allows the Agency to evaluate the appropriate numeric $NO_X$ standards associated with a BSER based on the use of post-combustion SCR in combination with combustion controls while also identifying under what conditions the emission standards are applicable.

TABLE 1—SUBPART KKKKa $NO_X$ EMISSION STANDARDS

| Combustion turbine type | Combustion turbine base load rated heat input (HHV) | $NO_X$ emission standard |
|---|---|---|
| New, firing natural gas with utilization rate >45 percent | >850 MMBtu/h | 5 ppm at 15 percent $O_2$ or 0.018 lb/MMBtu. |

[148] The capital costs may be approximately the same for turbines with $NO_X$ emission guarantees of 15 ppm or 9 ppm. The operation and maintenance costs are higher due to more rigorous maintenance requirements. *Cost Analysis of $NO_X$ Control Alternative for Stationary Gas Turbines,* ONSITE SYCOM Energy Corporation, November 5, 1999.

[149] To the extent any impacts are not explicitly covered under the ''nonair quality health and environmental impact'' factor, they are nonetheless statutorily relevant in identifying the ''best'' system of emissions reduction. *See* Section II.A.1 of this preamble.

[150] *See* section IV.B.2 of this preamble for additional discussion of the EPA's approach to subcategorization. *See* sections IV.B.3–4 for discussion of the EPA's application of the BSER criteria for these general control technology types, including further consideration of costs, emission reductions, and non-air quality health and environmental impacts and energy requirements, as applies to combustion turbines in the large, medium, and small subcategories. For additional discussion of the EPA's review of these control technologies, *see* the proposal, 89 FR 101323, and the technical support documents included in the docket for this rulemaking.

TABLE 1—SUBPART KKKKa $NO_X$ EMISSION STANDARDS—Continued

| Combustion turbine type | Combustion turbine base load rated heat input (HHV) | $NO_X$ emission standard |
|---|---|---|
| New, firing natural gas with utilization rate ≤45 percent and with design efficiency ≥38 percent. | >850 MMBtu/h | 25 ppm at 15 percent $O_2$ or 0.092 lb/MMBtu. |
| New, firing natural gas with utilization rate ≤45 percent and with design efficiency <38 percent. | >850 MMBtu/h | 9 ppm at 15 percent $O_2$ or 0.035 lb/MMBtu. |
| New, modified, or reconstructed, firing non-natural gas | >850 MMBtu/h | 42 ppm at 15 percent $O_2$ or 0.16 lb/MMBtu. |
| Modified or reconstructed, firing natural gas, at all utilization rates with design efficiency ≥38 percent. | >850 MMBtu/h | 25 ppm at 15 percent $O_2$ or 0.092 lb/MMBtu. |
| Modified or reconstructed, firing natural gas, at all utilization rates with design efficiency <38 percent. | >850 MMBtu/h | 15 ppm at 15 percent $O_2$ or 0.055 lb/MMBtu. |
| New, firing natural gas at utilization rates >45 percent | >50 MMBtu/h and ≤850 MMBtu/h. | 15 ppm at 15 percent $O_2$ or 0.055 lb/MMBtu. |
| New, firing natural gas at utilization rates ≤45 percent | >50 MMBtu/h and ≤850 MMBtu/h. | 25 ppm at 15 percent $O_2$ or 0.092 lb/MMBtu. |
| Modified or reconstructed, firing natural gas | >20 MMBtu/h and ≤850 MMBtu/h. | 42 ppm at 15 percent $O_2$ or 0.15 lb/MMBtu. |
| New, firing non-natural gas | >50 MMBtu/h and ≤850 MMBtu/h. | 74 ppm at 15 percent $O_2$ or 0.29 lb/MMBtu. |
| Modified or reconstructed, firing non-natural gas | >20 MMBtu/h and ≤850 MMBtu/h. | 96 ppm at 15 percent $O_2$ or 0.37 lb/MMBtu. |
| New, firing natural gas | ≤50 MMBtu/h | 25 ppm at 15 percent $O_2$ or 0.092 lb/MMBtu. |
| New, firing non-natural gas | ≤50 MMBtu/h | 96 ppm at 15 percent $O_2$ or 0.37 lb/MMBtu. |
| Modified or reconstructed, all fuels | ≤20 MMBtu/h | 150 ppm at 15 percent $O_2$ or 0.55 lb/MMBtu. |
| New, firing natural gas, either offshore turbines, turbines bypassing the heat recovery unit, and/or temporary turbines. | >50 MMBtu/h | 25 ppm at 15 percent $O_2$ or 0.092 lb/MMBtu. |
| Located north of the Arctic Circle (latitude 66.5 degrees north), operating at ambient temperatures less than 0 °F (−18 °C), modified or reconstructed offshore turbines, operated during periods of turbine tuning, byproduct-fired turbines, and/or operating at less than 70 percent of the base load rating. | ≤300 MMBtu/h | 150 ppm at 15 percent $O_2$ or 0.55 lb/MMBtu. |
| Located north of the Arctic Circle (latitude 66.5 degrees north), operating at ambient temperatures less than 0 °F (−18 °C), modified or reconstructed offshore turbines, operated during periods of turbine tuning, byproduct-fired turbines and/or operating at less than 70 percent of the base load rating. | >300 MMBtu/h | 96 ppm at 15 percent $O_2$ or 0.35 lb/MMBtu. |
| Heat recovery units operating independent of the combustion turbine | All sizes | 54 ppm at 15 percent $O_2$ or 0.20 lb/MMBtu. |

a. Large Combustion Turbines

As noted previously, the EPA is finalizing a size-based subcategory for stationary combustion turbines with base load ratings greater than 850 MMBtu/h of heat input (*i.e.,* large turbines).[151] The subcategory is divided further based on whether the annual utilization of the combustion turbine is greater than or less than or equal to a 12-calendar-month capacity factor of 45 percent. The large low-utilization combustion turbine subcategory includes separate subcategories based on whether the design efficiency of the turbine engine is 38 percent or greater based on the HHV of the fuel.

These emission standards for large combustion turbines only apply to new natural gas-fired sources operating at full load. In subpart KKKKa, the EPA establishes separate subcategories, BSER, and $NO_X$ standards for turbines operating at part load, turbines burning non-natural as fuels, and modified and reconstructed combustion turbines.

i. Large High-Utilization Combustion Turbines

This section describes the emissions standards in subpart KKKKa, based on the identified BSER, for the subcategory of new large stationary combustion turbines operated at high rates of utilization. The EPA is finalizing, largely as proposed, a determination that the use of combustion controls in combination with SCR is the BSER for large high-utilization combustion turbines operating at full load. The EPA proposed a $NO_X$ emission standard of 3 ppm for large natural gas-fired combustion turbines utilized at intermediate and high capacity factors and 5 ppm for the same combustion turbines when firing non-natural gas fuels. In the proposed rule, the EPA solicited comment on a range of 2 ppm to 5 ppm $NO_X$ when firing natural gas in recognition of the potential for some variation in SCR performance among different units and operating conditions.[152]

In response to the proposed rule, several commenters stated that the proposed emissions standard for large, high-utilization turbines firing natural gas of 3 ppm $NO_X$ is too stringent and not consistently achievable. Commenters provided descriptions and examples of how the effectiveness of SCR can be impacted by many factors, such as load changes and ambient conditions. For example, during variable load operation, the absolute mass of $NO_X$ entering the SCR system, the temperature of the combustion turbine exhaust, and exhaust flow characteristics change. Furthermore,

[151] Subcategories are based on the base load rating of the turbine engine and do not include any supplemental fuel input to the heat recovery system.

[152] See sections IV.7.a and IV.7.c for the final BSER determinations and $NO_X$ standards of performance for the subcategories of combustion turbines firing non-natural gas fuels and turbines operating at part load.

SCR performance is impacted by catalyst temperature and flow characteristics, and the ammonia injection rate must be adjusted to maintain the exhaust $NO_X$ emissions concentration. Too much ammonia injection can result in excess ammonia emissions (*i.e.,* ammonia slip) and too little can result in higher $NO_X$ emissions. In addition, commenters stated that it can be challenging to adjust ammonia injection rates during rapid load changes to maintain $NO_X$ emissions rates while at the same time minimizing ammonia slip, particularly for combustion turbines not selling electricity to the electric grid. Other commenters stated that emission standards of combustion turbines required to meet LAER should not be used to support the cost effectiveness of SCR as a control technology. Other commenters supported an emissions standard consistent with the lowest emitting turbines—2 ppm $NO_X$.

In consideration of these comments, to determine the appropriate $NO_X$ standard of performance for large high-utilization combustion turbines firing natural gas, the EPA also reviewed additional $NO_X$ emissions data reported to CAMPD. Specifically, the EPA reviewed the $NO_X$ emission rates of 91 combined cycle and CHP turbines at 46 separate stationary sources, and the $NO_X$ emissions rates of 143 simple cycle turbines at 43 separate stationary sources. The demonstrated natural gas-fired high-load emissions rates of the 26 recent large combined cycle and CHP turbines with SCR range from 1.5 ppm $NO_X$ to 8.4 ppm $NO_X$ with a median reported value of 2.7 ppm $NO_X$.[153] Two facilities had demonstrated emission rates greater than 5 ppm $NO_X$. One of the facilities is the first installation of a highly efficient combined cycle turbine that recently became commercially available.[154] While this turbine has a relatively high $NO_X$ emissions rate, the Agency anticipates that the manufacturer and owners or operators of future installations will learn from the performance of this initial installation. The other facility had higher emissions during the initial 6 months of operation and has demonstrated an emissions rate below 5 ppm $NO_X$ after this initial period. All other turbines have demonstrated that an emissions standard of 5 ppm $NO_X$ is achievable for combined cycle turbines. There are three turbines with emission rates between 4.3 ppm and 4.8 ppm $NO_X$. These are all high-efficiency turbines equipped with combustion controls capable of achieving 25 ppm $NO_X$ in combination with SCR. While not the only combined cycle facilities using these higher efficiency models, they account for the variability in performance at different locations. A more stringent standard could restrict the use of these highly efficient turbines and result in greater overall fuel use and the environmental impacts associated with increased fuel use.

While the EPA's SCR costing analysis primarily focused on large high-utilization combined cycle turbines, the EPA also evaluated the performance of large low-utilization simple cycle turbines with SCR to determine the achievability of the NSPS for these units in case owners or operators of new simple cycle combustion turbines choose to operate as high-utilization sources, assuming installation of SCR. The achievable $NO_X$ emissions rate of the four recent large simple cycle turbines with SCR ranges from 2.2 ppm to 30 ppm $NO_X$ with a median reported value of 11 ppm $NO_X$. Like the combined cycle turbine mentioned above, the highest emitting simple cycle turbine is the first installation of a higher efficiency model that recently became commercially available. While this turbine has a relatively high $NO_X$ emissions rate, the Agency anticipates that the manufacturer and owners or operators of future installations will learn from the performance of this initial installation. The $NO_X$ emissions standards for the remaining three turbines range from 2.2 ppm to 7.3 ppm $NO_X$. There is one other highly efficient large simple cycle turbine with SCR that has been installed. This facility uses a different turbine model that began operation in 2019 and has been able to achieve an emission rate of 9 ppm $NO_X$. While none of the large higher efficiency simple cycle turbines have demonstrated that 5 ppm $NO_X$ is consistently achievable, the Agency does not project any large simple cycle turbine operating as high-utilization turbines. However, the mass-based standard allows large higher efficiency simple turbines with SCR to operate in excess of a 12-calendar-month utilization rate of 45 percent while maintaining compliance with the NSPS.

Due to the limited number of large simple cycle turbines with SCR, the EPA also reviewed the performance of recent medium low-utilization simple cycle turbines with SCR. The $NO_X$ emissions rate of the 62 recent medium simple cycle turbines with SCR ranges from 2 ppm to 26 ppm $NO_X$ with a median reported value of 6.8 ppm $NO_X$. While only 37 percent of recent medium simple cycle turbines have maintained an emissions rate of 5 ppm $NO_X$ or less, the Agency finds that 5 ppm is an appropriate emissions standard for high-utilization large simple cycle turbines. Turbines operating at higher utilizations would have steadier loads and the operator would be able to optimize the SCR for greater emission reduction.

Considering these factors, the EPA is finalizing a $NO_X$ standard of performance of 5 ppm for large high-utilization turbines firing natural gas based on the application of a BSER of combustion controls in combination with SCR. Available data indicate that SCR installed on new large stationary combustion turbines, when operated in conjunction with combustion controls, is generally capable of achieving a $NO_X$ emissions rate of 5 ppm when combustion turbines are operating at high rates of utilization and firing natural gas. Therefore, for this subcategory of stationary combustion turbines for which the EPA determines SCR is a component of the BSER and which are firing natural gas, the EPA determines that the emissions standard is 5 ppm. For new large combustion turbines operating at high rates of utilization and firing non-natural gas fuels, the EPA determines the $NO_X$ standard to be 42 ppm based on the application of a BSER of wet combustion controls with the addition of post-combustion SCR.

While some combustion turbine facilities have generally been capable of reaching an emissions rate of 3 ppm or less, the 5-ppm emissions standard in this case will allow sources to use higher efficiency classes of turbines in combined cycle configurations, to use combustion controls without SCR, and to minimize ammonia emissions.

The EPA finds some commenters' call for a 2 ppm $NO_X$ emissions standard to be unrealistically stringent. Only two-thirds of recent (*i.e.,* since 2020 large, combined cycle turbines and no simple cycle facility evaluated by the EPA have been able to achieve an emissions rate of 2 ppm $NO_X$. As a practical matter, it would prohibit the use of high-utilization simple cycle turbines with SCR, and to maintain any compliance

[153] The EPA determined the achievable emissions rate for each turbine by calculating the 99.9 percentile of the 4-hour rolling averages using full load hours when only natural gas was the reported fuel. Combustion turbines with reported achievable emission rates that are 10 percent or higher than the applicable standard under subpart KKKK were excluded from the calculations when reporting the demonstrated emission rates for combustion turbines.

[154] The EPA only evaluated the reported data 6 months after initial operation to account for the initial shake down period. The EPA is also excluding the initial 6 months of operation for combustion turbines where it appears the SCR might not have been consistently operated.

margin, would at a minimum restrict developers of new combined cycle turbines to use turbine designs with the lowest emitting combustion controls in combination with SCR and high ammonia injection rates. This would result in increased costs, fuel use, and ammonia emissions. Thus, while the EPA acknowledges that some combustion turbine facilities have generally been capable of reaching an emissions rate of 2 or 3 ppm using SCR, the Agency believes it is important that all of the combustion turbines in the subcategory for which SCR is the BSER are capable of achieving the emissions standard, taking into account natural variability and temporary fluctuations in emissions performance, as well as cost, fuel, and emissions downsides associated with a more stringent emissions standard.

Finally, as the EPA noted at proposal, an emissions standard of 5 ppm can also potentially be met by certain classes of stationary combustion turbines solely with the use of advanced combustion controls rather than SCR. Given that SCR has some additional cost, pollutant, and energy impacts associated with it, there is benefit to a standard that at least some sources may be capable of meeting without installing SCR, and which will help incentivize the further development and deployment of increasingly advanced combustion controls. Thus, the $NO_X$ standard for large high-utilization turbines is set at an emissions rate that also recognizes the environmental benefit of continued development of combustion controls, which, if capable of achieving the same or similar emissions performance, have substantial advantages over SCR.

ii. Large Low-Utilization Combustion Turbines

For large combustion turbines utilized at low capacity factors, the EPA proposed that the BSER is the use of dry combustion controls when firing natural gas and wet combustion controls when firing non-natural gas fuels. The EPA proposed on that basis to maintain the same $NO_X$ emission standards as in subpart KKKK for large combustion turbines utilized at low capacity factors—15 ppm for natural gas-fired turbines and 42 ppm for non-natural gas-fired turbines.

(A.) Higher Efficiency Combustion Turbines

This section describes the emissions standards the EPA is finalizing in subpart KKKKa, based on the identified BSER, for the subcategory of new large stationary combustion turbines operated at low rates of utilization and with higher efficiencies. Specifically, this subcategory includes combustion turbines with a base load rating greater than 850 MMBtu/h of heat input, a 12-calendar-month capacity factor less than or equal to 45 percent, and a design efficiency greater than or equal to 38 percent based on the HHV of the fuel.

Commenters noted that large turbines with simple cycle design efficiencies of 38 percent or greater all have guaranteed $NO_X$ emission rates of 25 ppm and have become commercially available since subpart KKKK was finalized. Based on the BSER analysis in section IV.B.3 of this preamble, the EPA determines that SCR does not qualify as the BSER for these turbines. The only commercially available combustion controls are guaranteed at 25 ppm $NO_X$. Therefore, for this subcategory of stationary combustion turbines for which the EPA determines combustion controls to be the BSER and which are firing natural gas, the EPA determines that the $NO_X$ standard of performance is 25 ppm. Likewise, for this subcategory, the EPA determines that the $NO_X$ emissions standard is 42 ppm when firing non-natural gas fuels (based on the use of wet combustion controls) and 96 ppm when operating at less than 70 percent of the base load rating (based on the use of diffusion flame combustion). The EPA is not aware of any advances in wet combustion controls that would reduce $NO_X$ emissions lower than the emission standards in subpart KKKK when large combustion turbines are using non-natural gas fuels.

(B.) Lower Efficiency Combustion Turbines

This section describes the emissions standards for new large stationary combustion turbines operated at low rates of utilization and with lower efficiencies. Specifically, this subcategory includes combustion turbines with a base load rated heat input greater than 850 MMBtu/h, a 12-calendar-month capacity factor less than or equal to 45 percent, and a design efficiency less than 38 percent based on the HHV of the fuel.

For this subcategory, the EPA determines that SCR does not meet the BSER criteria and that the BSER is the use of advanced dry combustion controls when firing natural gas, the use of wet combustion controls when firing non-natural gas fuels, and the use of diffusion flame combustion when operating at less than 70 percent of the base load rating (*i.e.,* when operating at part load).

The BSER for large, low-utilization, lower efficiency combustion turbines burning natural gas is the use of advanced combustion controls. The EPA reviewed the standard $NO_X$ guaranteed emission rates of 13 commercially available large combustion turbines with design efficiencies less than 38 percent. Five of the turbines have standard guarantees of 9 ppm $NO_X$. Four of the turbines have standard guarantees of 15 ppm $NO_X$, and four of the turbines have standard guarantees of 25 ppm $NO_X$.

Of the four turbines with 15 ppm $NO_X$ standard guarantees, two have available upgrade packages that reduce the guaranteed emissions rate to 9 ppm $NO_X$ or less. In addition, the manufacturer of one of the other turbines has developed a newer design that is similar in size, more efficient, and available with combustion controls guaranteed at 9 ppm $NO_X$. The remaining 15-ppm turbine is on the lower end of the large turbine subcategory (905 MMBtu/h and 88 MW) and the manufacturer offers a similar size, but less efficient, frame type turbine with emission guarantees of 9 ppm $NO_X$ or less. The same manufacturer also offers similar sized aeroderivative turbines with significantly higher efficiencies that would be classified as a medium turbine (660 MMBtu/h and 71 MW) that can meet the low-utilization medium turbine emissions standard without SCR. As noted previously, large low-utilization turbines are primarily used in the utility sector and the fuel flexibility and other characteristics of frame type turbines are not as critical. Therefore, the EPA finds that many turbine models with emission guarantees of 9 ppm $NO_X$ exist that can meet the needs for all owners or operators. As such, the EPA finds that 9 ppm is the appropriate standard of performance for new large low-utilization lower efficiency combustion turbines firing natural gas.

Even for large, lower efficiency turbine models not manufactured to meet a 9-ppm emissions standard, the EPA generally anticipates that these models will continue to be sold and operated at little incremental cost under this rule, because this is already occurring in the commercial marketplace. Three of the four large, lower efficiency turbine models with 25 ppm $NO_X$ guarantees were available when subpart KKKK was finalized and have been subject to an emissions standard of 15 ppm $NO_X$ since 2006. The remaining large turbine with a 25 ppm $NO_X$ guarantee became commercially available in 2013 but is primarily intended for combined cycle applications.[155] In any case, under subpart KKKK, these turbine models have continued to be marketed and typically install and operate SCR to meet the subpart KKKK 15 ppm standard. The EPA anticipates that updating the emissions standard for turbines in this subcategory from an emissions rate of 15 ppm to 9 ppm will not induce a change in how these turbine models are currently brought to market or used. In other words, even if their manufacturers, owners, or operators elect not to upgrade the combustion control performance to achieve a 9-ppm rate, they will still be able to meet the new standard using SCR, as is already occurring in the baseline under subpart KKKK. In the case of continued use of SCR for these turbine models, the EPA calculates a slight increase in incremental costs associated with going from a 15 ppm $NO_X$ emissions standard to a 9 ppm $NO_X$ emissions standard. Specifically, the Agency estimates that the incremental costs to achieve the standard in KKKKa for these turbines using SCR is from the use of additional ammonia for a cost effectiveness of $1,000/ton. These costs are reasonable.

To confirm that a 9 ppm $NO_X$ standard is appropriate, the EPA also reviewed the turbine models of the 20 large simple cycle turbines that have commenced operation in the utility sector since 2020. Four of these units use SCR and the other 16 units do not. The 16 turbines without SCR are models that have emission guarantees of 9 ppm $NO_X$ and the reported emission rates support that the combustors are achieving 9 ppm $NO_X$. As discussed previously, these data support finding that the BSER need not include SCR. Therefore, lowering the emissions standard from 15 ppm to 9 ppm for large low-utilization, lower efficiency turbines would not represent significant costs to the regulated community.

For this subcategory, the EPA determines that the $NO_X$ emissions standard is 42 ppm when firing non-natural gas fuels and 96 ppm when operating at less than 70 percent of the base load rating.

b. Medium Combustion Turbines

The EPA is finalizing a size-based subcategory for stationary combustion turbines with base load ratings greater than 50 MMBtu/h and less than or equal to 850 MMBtu/h of heat input (*i.e.,* medium). As discussed in section IV.B.2.b of this preamble, the subcategory is divided further based on whether the annual utilization of the combustion turbine is greater than or less than or equal to a 12-calendar-month capacity factor of 45 percent.

i. Medium High-Utilization Combustion Turbines

The EPA proposed the use of combustion controls with SCR as the BSER for medium intermediate- and high-utilization combustion turbines operating at full load and a $NO_X$ emissions standard of 3 ppm when firing natural gas and 9 ppm when firing non-natural gas. The EPA proposed the use of diffusion flame combustion as the BSER when operating at part load with a $NO_X$ emissions standard of 96 ppm or 150 ppm (depending on the base load rating of the individual turbine). For this subcategory, as described in section IV.B.3, the EPA has determined that SCR does not meet the BSER criteria for new medium high-utilization combustion turbines (*i.e.,* those with 12-calendar-month capacity factors greater than 45 percent). In subpart KKKKa, the BSER for medium high-utilization combustion turbines is the use of advanced dry combustion controls when firing natural gas, wet combustion controls when firing non-natural gas fuels, and diffusion flame combustion when operating at part load (*i.e.,* less than 70 percent of the base load rating).

In response to the proposed rule, several commenters stated that the proposed 3 ppm $NO_X$ limit for medium-sized units operating at 20 percent to 40 percent capacity factors are not achievable without SCR. The commenters added that based on guarantees from manufacturers, the EPA should increase the proposed $NO_X$ limit from 3 ppm to 9 ppm for medium-sized units operating at capacity factors of less than 40 percent based on the use of dry combustion controls. Furthermore, a review of EPRI research found that most dry combustion control $NO_X$ guarantees ranged from 9 ppm to 25 ppm. The commenters stated that the EPA's data showed that not all dry combustion controls can achieve 15 ppm $NO_X$ for medium-sized turbines. The commenters stated that the most efficient combustion turbines operate at higher temperatures, which results in higher $NO_X$ emissions.

The EPA agrees with the commenters that manufacturer $NO_X$ emission rate performance guarantees for medium natural gas-fired stationary combustion turbines using dry combustion controls range from 9 ppm to 25 ppm. While a few natural gas-fired high-efficiency aeroderivative combustion turbines have available combustor upgrades that have $NO_X$ emission rate performance guarantees of 15 ppm, most have standard $NO_X$ emission rate performance guarantees of 25 ppm. However, most natural gas-fired frame units using dry combustion controls have available guaranteed $NO_X$ emissions rates of 15 ppm or lower; of these, half have standard emission guarantees of 15 ppm $NO_X$ or less and only four frame units do not have available combustor options with guarantees of less than 25 ppm $NO_X$. The manufacturer of these four turbines offers models with similar outputs, often with higher efficiencies, that have guaranteed emission rates of 15 ppm $NO_X$ or less available. The fact that frame units with dry combustion controls are more common than aeroderivative or turbines using wet controls at high utilization rates supports a standard for medium high-utilization turbines of 15 ppm $NO_X$. The EPA considered, but rejected, the use of combustion controls with guaranteed emission rates of 9 ppm $NO_X$ as the BSER. Many of the most efficient medium turbines are aeroderivative turbines and only a select few have available emission guarantees of less than 25 ppm $NO_X$. Maintaining a high-utilization emissions standard of 15 ppm $NO_X$ provides a strong incentive for manufacturers to invest in technology development and commercialize combustors with 15 ppm $NO_X$ emission guarantees. In addition, while 13 turbines offer available combustor upgrades with $NO_X$ emission guarantees of 9 ppm, only two models have standard guarantees of 9 ppm $NO_X$. An emissions standard more stringent than 15 ppm would likely require the use of SCR for many applications, and the Agency has determined that SCR does not meet the BSER criteria for medium turbines.

With the adjustments in subcategories described in section IV.B.2, and the associated BSER analysis for combustion controls in section IV.B.4, the EPA is finalizing a $NO_X$ emissions standard of 15 ppm for this subcategory when firing natural gas. The $NO_X$ emission standards are 74 ppm when combusting non-natural gas fuels and 96 ppm or 150 ppm (depending on the base load rating) when operating at part load. These $NO_X$ standards are based on the application of dry and/or wet combustion controls at full load and diffusion flame combustion at part load.

ii. Medium Low-Utilization Combustion Turbines

The medium low-utilization turbine subcategory is primarily composed of

[155] The same manufacturer offers a slightly smaller turbine (260 MW compared to 310 MW) that was commercially available when subpart KKKK was finalized. The smaller turbine has the same simple cycle efficiency and has a guaranteed $NO_X$ emissions rate of 9 ppm.

utility sector simple cycle turbines, the majority of which are aeroderivative designs equipped with SCR. However, as described in section IV.B.3 of this preamble, the EPA has determined that SCR does not meet the BSER criteria for any medium combustion turbines. The EPA proposed a $NO_X$ emissions standard of 25 ppm for medium low-utilization combustion turbines (*i.e.,* those with 12-calendar-month capacity factors less than or equal to 45 percent) firing natural gas, 74 ppm $NO_X$ when firing non-natural gas, and 96 ppm or 150 ppm (depending on the base load rating) when operating at part load (*i.e.,* at less than 70 percent of the base load rating).

Regarding emission standards associated with combustion controls, some commenters supported the proposed emission standards, stating that most aeroderivative combustion turbines and combustion turbines using wet combustion controls have emission guarantees of 25 ppm $NO_X$.

The EPA agrees with commenters and is finalizing a BSER of combustion controls for this subcategory. The reported emissions rates of these turbines indicate that they are using combustion turbines and controls with emission guarantees of 25 ppm $NO_X$ or less. The medium low-utilization turbines without SCR appear to be using units with $NO_X$ emission guarantees of 25 ppm $NO_X$. An emissions standard of 25 ppm $NO_X$ is consistent with the guaranteed emissions rate of most aeroderivative turbines that have characteristics that make them valuable for low-utilization applications—they can start quickly without increasing maintenance requirements and they have relatively high efficiency. Although the EPA's BSER determination is based on its conclusion that dry combustion controls are reasonable for the subcategory, in certain applications or circumstances (notably for the lowest utilization peaking turbines), wet combustion controls that can achieve the same emission rate (25 ppm $NO_X$) potentially have comparative advantages in terms of cost. This overlap corroborates the reasonableness of a final emission standard of 25 ppm $NO_X$, which can be achieved using either wet or dry combustion controls. Therefore, the Agency is finalizing the emissions standard as proposed.

The emission standards for new medium stationary combustion turbines operating at low rates of utilization (*i.e.,* at 12-calendar-month capacity factors less than or equal to 45 percent) is 25 ppm. For low-utilization medium turbines firing non-natural gas fuels, the $NO_X$ standard in subpart KKKKa is 74 ppm.

c. Small Combustion Turbines

The EPA is finalizing a size-based subcategory for stationary combustion turbines with base load ratings less than or equal to 50 MMBtu/h of heat input (*i.e.,* small). The final BSER for all turbines in this subcategory is combustion controls.

The EPA proposed $NO_X$ emission standards of 3 ppm for small natural gas-fired combustion turbines that operate at high utilization rates and 9 ppm for the same combustion turbines when firing non-natural gas fuels. The EPA proposed $NO_X$ emission standards for small combustion turbines utilized at intermediate and low utilization rates of 25 ppm for natural gas-fired turbines, 74 ppm for non-natural gas-fired turbines, and 150 ppm for turbine operating at part loads.

With respect to emission standards associated with combustion controls, some commenters supported maintaining the subpart KKKK emission standard for small turbines—42 ppm $NO_X$ for electric generating and 100 ppm $NO_X$ for mechanical drive applications. Other commenters stated that space constraints do not allow the same combustor design considerations as for larger turbines and that small turbines cannot achieve less than 25 ppm $NO_X$.

As discussed in section IV.B.3 of this preamble, the EPA has determined that SCR does not meet the BSER criteria for small combustion turbines at any utilization level. The Agency therefore has determined that combustion controls remain the BSER for the subcategory. The EPA agrees with commenters that combustion controls are more limited for small turbines than medium and large turbines. To determine the appropriate emissions standard the EPA reviewed information on manufacturer $NO_X$ emission guarantees. One small turbine has a $NO_X$ emissions rate guarantee of 5 ppm and a high design efficiency. However, this is a higher-cost recuperated turbine model that is only capable of burning natural gas (*i.e.,* not dual-fuel capable). The fuel limitation does not cover the source category as a whole and the EPA has determined the performance of this single turbine should not be used when establishing the $NO_X$ emissions standard for this subcategory. Most of the remaining turbines have emission guarantees of 25 ppm $NO_X$. The EPA considered, but rejected, an emissions standard of 15 ppm $NO_X$. Turbines with 15 ppm $NO_X$ guarantees are only available in the 2 MW size category and this would require the use of SCR on the 1.5 MW and 3.5 MW turbines in the source category. As many of these turbines are used in industrial mechanical applications, it is necessary to match the load to the output of the turbine. Restricting the availability of turbines would result in turbines running at part load, which would result in inefficient operation and higher $NO_X$ emission rates or the use of higher-emitting reciprocating engines. Therefore, the EPA has determined that the BSER for small natural gas-fired turbines is dry combustion controls that can meet a $NO_X$ emission rate of 25 ppm, and the emissions standard for these turbines is 25 ppm. The EPA notes that this emissions standard is also achievable using wet combustion controls.

The EPA is not aware of any improvements in the performance of wet combustion controls or improvements in the part-load performance for these combustion turbines. Therefore, the EPA is maintaining the same standards as in subpart KKKK—96 ppm when firing non-natural gas fuels and 150 ppm when operating at part load (*i.e.,* at less than 70 percent of the base load rating).

6. Revised NSPS for Modified and Reconstructed Stationary Combustion Turbines

This section describes the BSER and emission standards for modified and reconstructed stationary combustion turbines subject to subpart KKKKa. The EPA proposed to include reconstructed stationary combustion turbines in the same size-based subcategories as new stationary combustion turbines. The EPA believed at proposal that reconstructed turbines could likely incorporate the same technologies to reduce $NO_X$ as part of the reconstruction process at little or no additional cost compared to a greenfield facility. Therefore, the EPA proposed BSERs and $NO_X$ standards of performance for large, medium, and small reconstructed combustion turbines were identical to those proposed for new combustion turbines for each size-based subcategory. Identical rationale applied to modified large combustion turbines, which we proposed to subcategorize with the same BSER and $NO_X$ standards of performance as new and reconstructed large turbines.

For modified medium and small combustion turbines, the EPA proposed that the BSER is the use of combustion controls and that SCR did not qualify as part of the BSER for these sources due to potentially high retrofit costs, regardless of level of utilization. Based on the BSER of combustion controls, the EPA proposed $NO_X$ standards of performance for all modified medium and small combustion turbines of 25 ppm when firing natural gas and 74 ppm when firing non-natural gas fuels.

Several commenters criticized the EPA's proposal to subcategorize modified and reconstructed turbines with BSER and $NO_X$ emission standards identical to new turbines, including the proposed BSER determinations with respect to SCR. These commenters stated that subpart KKKKa should group reconstructed units with modified turbines because the same retrofit technology limitations and cost factors apply. Another commenter, however, asserted that it is more difficult and expensive to retrofit an existing unit to meet more stringent standards. For example, some owners or operators might have to pay millions of dollars to replace and redesign the HRSG to retrofit the unit with SCR in addition to the millions of dollars spent in SCR capital costs. Reconstruction costs are also higher because of factors such as downtime, demolition, space constraints, and replacement of equipment. The commenter stated that the EPA did not adequately support grouping reconstructed and new combustion turbines together and that the proposed NSPS should have included a more thorough analysis before applying SCR as part of the BSER for reconstructed turbines.

The EPA agrees with commenters' assertions that the costs of retrofitting combustion turbines with SCR is significantly higher than for new turbines. Consequently, the EPA is determining that SCR does not qualify as the BSER for reconstructed or modified large high-utilization combustion turbines and is finalizing separate BSER and standards for such turbines. In subpart KKKK, the standards for modified and reconstructed combustion turbines are generally higher for a given subcategory than for newly constructed turbines because combustion controls can be more challenging to apply to modified and reconstructed combustion turbines compared to newly constructed combustion turbines. The different $NO_X$ standards for modified and reconstructed combustion turbines with the same BSER as new combustion turbines are necessary because lean premix/DLN technology is specific to each combustion turbine model (*i.e.,* a combustor designed for a particular turbine model cannot simply be installed on a different turbine model).

In subpart KKKKa, the EPA is determining that the use of combustion controls alone (without SCR) is the BSER for modified and reconstructed combustion turbines of all sizes. For modified and reconstructed stationary combustion turbines with base load ratings less than or equal to 20 MMBtu/h of heat input (*i.e.,* small), the EPA is not aware of technology developments and therefore the numerical $NO_X$ standard for all small modified and reconstructed turbines in subpart KKKKa is the same as the $NO_X$ standard in subpart KKKK. All small modified and reconstructed stationary combustion turbines are subject to a $NO_X$ emissions standard of 150 ppm whether they burn natural gas or non-natural gas fuels. The EPA has determined that modified and reconstructed combustion turbines with base load ratings between 20 MMBtu/h and 850 MMBtu/h can achieve the same emissions rates as larger turbines and these turbines are subcategorized as medium turbines. The EPA is not aware of technological developments for modified or reconstructed medium combustion turbines and is therefore maintaining the emission standards in subpart KKKK—42 ppm $NO_X$ for modified and reconstructed medium natural gas-fired combustion turbines and 96 ppm $NO_X$ for modified and reconstructed medium non-natural gas-fired combustion turbines. Modified and reconstructed combustion turbines cannot achieve the same emissions rates as new combustion turbines because manufacturers have not developed combustor upgrade packages for all combustion turbines and even for specific models with combustor upgrade packages there might physical space constraints making the combustor upgrade impractical. Similarly, for modified and reconstructed large lower efficiency and non-natural gas-fired turbines the EPA is finalizing emissions standards consistent with subpart KKKK—15 ppm $NO_X$ for large lower efficiency natural gas-fired combustion turbines and 42 ppm $NO_X$ for large non-natural gas-fired combustion turbines. For modified and reconstructed large natural gas-fired higher efficiency combustion turbines the EPA is finalizing an emissions standard consistent with that for newly constructed combustion turbines—25 ppm $NO_X$. For modified and reconstructed large high utilization turbines that EPA has determined that even if the practical limitations can be overcome the cost of retrofitting SCR is not reasonable.

7. Revised NSPS for Other Subcategories of Stationary Combustion Turbines

a. Non-Natural Gas Emissions Standard

The EPA is not aware of any advances in $NO_X$ combustion controls for non-natural gas-fired fuels relative to the analysis it conducted for subpart KKKK in 2006. Dry combustion controls have limited applicability to liquid fuels because the technology typically functions by premixing gaseous fuels and air into a homogenous mixture prior to combustion, which is not possible with liquid fuels. Advancements in wet combustion controls are limited by the amount of water that can be injected before the flame is prematurely quenched, resulting in increased CO and unburned hydrocarbon emissions. Contrary to dry combustion controls, this limitation of wet combustion controls does not prevent the technology from effectively reducing $NO_X$ emissions during the combustion of liquid fuels. Wet combustion controls just do not reduce $NO_X$ emissions as effectively as dry combustion controls when gaseous fuels are burned. Therefore, in subpart KKKKa, the EPA maintains that wet combustion controls (*i.e.,* water or steam injection) are the BSER for new, modified, or reconstructed stationary combustion turbines that burn non-natural gas fuels.

In subpart KKKKa, based on application of the BSER of wet combustion controls, the EPA maintains the $NO_X$ emissions standards for each subcategory of new, modified, or reconstructed combustion turbines firing non-natural gas.[156] Specifically, for large turbines, the EPA maintains a $NO_X$ standard of 42 ppm for all new, modified, or reconstructed turbines firing non-natural gas fuels. For medium combustion turbines, the EPA maintains $NO_X$ standards of 74 ppm $NO_X$ for new turbines and 96 ppm for modified and reconstructed combustion turbines when firing non-natural gas fuels. For small combustion turbines, the EPA maintains a $NO_X$ standard of 96 ppm for new turbines and 150 ppm $NO_X$ for modified and reconstructed turbines.

b. Combustion Turbines Firing Hydrogen

The EPA proposed that combustion turbines that burn less than or equal to 30 percent (by volume) hydrogen (blended with natural gas) should be subcategorized as natural gas-fired combustion turbines and subject to the same BSER and $NO_X$ standards of performance as other new, modified, or reconstructed natural gas-fired

[156] *See* table 1 in section IV.B.5 of this preamble.

combustion turbines.[157] For combustion turbines that burn greater than 30 percent (by volume) hydrogen (blended with natural gas), the EPA proposed to subcategorize these sources as non-natural gas-fired combustion turbines and the applicable $NO_X$ limit was proposed to be the same as the standard for non-natural gas-fired combustion turbines, again, depending on the particular size-based subcategory listed in table 1 of this preamble.

The proposal also included a solicitation for comment on the proposed 30 percent (by volume) hydrogen threshold and its appropriateness for determining whether an affected source should be subject to the $NO_X$ standard for natural gas or non-natural gas fuels. We also sought comment on the costs associated with co-firing high percentages (by volume) of hydrogen, including information about hydrogen-ready turbine designs, components, upgrades, and retrofits. The EPA also requested data from co-firing demonstrations, especially $NO_X$ emissions data associated with the performance of various combustion controls with and without SCR.

In response to the proposed rule, commenters asserted that the importance of establishing $NO_X$ standards of performance for combustion turbines co-firing hydrogen in subpart KKKKa considering the characteristics of hydrogen gas and the potential for increased formation of thermal $NO_X$ from its combustion. Some commenters stressed the need for further research because the efficacy of hydrogen co-firing, including critical issues of fuel costs and availability, is not yet fully established. Other commenters stated that while some demonstrations of co-firing hydrogen with natural gas have been conducted, and the results have been promising regarding $NO_X$ emissions, there is insufficient industry experience and data at this time to support the EPA's proposal that turbines co-firing up to 30 percent hydrogen (by volume) can consistently meet the natural gas $NO_X$ standard for each size-based subcategory. Several of the commenters who stated that it is premature to establish $NO_X$ standards of performance for hydrogen co-firing commensurate with the $NO_X$ standards for natural gas-fired combustion turbines also stated that the EPA should subcategorize hydrogen co-firing like the approach for non-natural gas fuels with a separate BSER and $NO_X$ standards.

In accordance with the limited data received in response to the proposal, the EPA agrees that the $NO_X$ emissions rate of combustion turbines co-firing hydrogen includes uncertainty and remains in the early stages of research and development. The EPA also recognizes the concerns of several commenters that the co-firing of hydrogen gas does increase the temperature of combustion, and a higher firing temperature leads to the formation of thermal $NO_X$. However, until more data is available about the performance of different sizes and designs of combustion turbines co-firing various percentages of hydrogen (by volume), and the performance of different combustion controls under those conditions, at this time the Agency is not able to establish hydrogen-specific $NO_X$ standards of performance in subpart KKKKa as proposed.

Even though subpart KKKKa does not establish $NO_X$ standards for hydrogen co-firing that are determined according to a specific percentage of hydrogen (by volume) blended with natural gas, in this final action, the subcategories of fuel-based $NO_X$ standards in subpart KKKKa would apply to all new, modified, and reconstructed combustion turbines that elect to co-fire hydrogen. It is the EPA's understanding that hydrogen is generally mixed with natural gas prior to entering the combustor, and once the heating value or the methane concentration of the fuel blend no longer meets the definition of natural gas in 40 CFR 60.4420a, the fuel would be considered a non-natural gas fuel and subject to the non-natural gas $NO_X$ standards for those operating hours.

In terms of percentages of hydrogen (by volume), this means that when a combustion turbine co-fires up to approximately 25 percent hydrogen (by volume), the blended fuel meets the definition of natural gas and would be subject to the size-based subcategory $NO_X$ standard for a turbine firing natural gas. If the blended fuel is greater than approximately 25 percent (by volume) hydrogen, the fuel no longer meets the definition of natural gas and the size-based subcategory $NO_X$ standards for non-natural gas fuels apply.

The EPA acknowledges that there is not much practical difference between establishing a subcategory and $NO_X$ standard based on a co-firing limit of 30 percent (by volume) hydrogen and the approximate 25 percent threshold that results from the application of the definition of natural gas in subpart KKKKa. But based on limited data, we are not able to support a determination that more stringent $NO_X$ standards for hydrogen co-firing are applicable at this time.

Again, based on limited data, the EPA expects that the performance of combustion controls without SCR will be effective at limiting the formation of thermal $NO_X$ in accordance with the $NO_X$ standards for natural gas and non-natural gas fuels when co-firing with hydrogen. The EPA notes that if the hydrogen and natural gas are fed into the combustor with separate burners, the applicable $NO_X$ standard would be calculated differently. If the energy content is greater than 50 percent of the heat input, the non-natural gas standard would be applicable. At lower mixing levels, the applicable hourly $NO_X$ standard would be prorated based on the relative heat input of the hydrogen and natural gas.[158]

See the 2024 Proposed Rule preamble (89 FR 101338; December 13, 2024) for additional information about hydrogen co-firing in stationary combustion turbines, including sections III.B.14.a through III.B.14.d for discussions of the characteristics of hydrogen gas that impact $NO_X$ emissions, hydrogen and combustion controls, hydrogen and SCR, and future combustion turbine capabilities.

c. Part-Load $NO_X$ Standards

As discussed previously in section IV.B.2.g of this preamble, existing subpart KKKK subcategorizes stationary combustion turbines operating at part load (*i.e.,* less than 75 percent of the base load rating) and combustion turbines operating at low ambient temperatures.[159] The hourly $NO_X$ emissions standard is less stringent during any hour when either of these conditions is met regardless of the type of fuel being burned. Subpart KKKK also has different hourly $NO_X$ emissions standards depending on if the output of the combustion turbine is less than or equal to 30 MW (150 ppm $NO_X$) or greater than 30 MW (96 ppm $NO_X$) during part-load operation or when operating at low ambient temperatures. As described in section IV.B.2.g of this preamble, in subpart KKKKa, the EPA is changing this size threshold for this subcategory such that the 150 ppm $NO_X$

[157] *See* table 1 in section IV.B.5 for a list of the size-based subcategories in subpart KKKKa and *see* 40 CFR 60.4420a for the definition of natural gas.

[158] Instructions for calculating $NO_X$ emissions on a lb/MMBtu basis, based upon the ratio of natural gas to hydrogen (by percent volume) in the fuel blend, is included in the memorandum *Fuel-Based F-Factors for Firing of Hydrogen and Hydrogen Blends in Combustion Turbines* located in the docket for this rulemaking (*See* Docket ID No. EPA–HQ–OAR–2024–0419).

[159] While the EPA refers to this as the part-load standard, it includes an independent temperature component as well.

emissions standard would be applicable to combustion turbines with base load ratings less than or equal to 300 MMBtu/h of heat input and the 96 ppm $NO_X$ emissions standard would be applicable to combustion turbines with base load ratings greater than 300 MMBtu/h. In subpart KKKKa, the EPA maintains that the BSER for turbines operating at part load or at low ambient temperatures is diffusion flame combustion for all fuel types. Thus, the EPA also maintains, based on the application of diffusion flame combustion, that the part-load and low ambient temperature $NO_X$ emission standards are 150 ppm for turbines with base load ratings of less than or equal to 300 MMBtu/h of heat input and 96 ppm for combustion turbines with base load ratings greater than 300 MMBtu/h. In addition, the proposed part-load standard includes all periods of part-load operation, including startup and shutdown. However, in contrast to the part-load standards in subpart KKKK, in subpart KKKKa, the EPA lowers the part-load threshold from less than 75 percent load to less than 70 percent of the combustion turbine's base load rating.[160]

The part-load emissions standards effectively accommodate periods of startup and shutdown for this source category. The determination to maintain the BSER and $NO_X$ emission standards in subpart KKKKa for combustion turbines operating at part load or low ambient temperatures is based on a review of reported maximum emissions rate data for recently constructed combustion turbines. The data includes all periods of operation, including periods of startup and shutdown. For combustion turbines with base load ratings of greater than 300 MMBtu/h and that recently commenced operation, 80 percent of simple cycle turbines and 98 percent of combined cycle turbines reported a maximum $NO_X$ emissions rate of less than 96 ppm. Based on this information, in subpart KKKKa, the EPA maintains that a part-load standard of 96 ppm, which includes periods of startup and shutdown, is appropriate for combustion turbines with base load ratings of greater than 300 MMBtu/h of heat input. The EPA does not have CEMS data for combustion turbines with base load ratings of less than 250 MMBtu/h of heat input and maintains the existing part-load standard in subpart KKKKa of 150 ppm $NO_X$.

Since startups and shutdowns are part of the regular operating practices of stationary combustion turbines, subpart KKKKa includes a part-load $NO_X$ emissions standard that applies during periods of startup and shutdown. Since periods of startup and shutdown are by definition periods of part load, and since the "part-load standard" is based on the emissions rate achieved by a diffusion flame combustor instead of the combustion controls and/or SCR otherwise identified as the BSER, the Agency concludes that this standard is appropriate to accommodate periods of startup and shutdown. Through analysis of CEMS data, the EPA determines that, given the part-load limits, including periods of startup and shutdown would not result in non-compliance with the NSPS. This also ensures this rule complies with the statutory requirement that NSPS standards of performance apply on a continuous basis.[161] The EPA analyzed $NO_X$ CEMS data from existing multiple combustion turbines and the theoretical compliance rate with a 4-hour rolling average, including all periods of operation, was demonstrated to be achievable.[162]

d. Site-Specific $NO_X$ Standard

The EPA is finalizing as proposed a provision allowing for a site-specific $NO_X$ standard for an owner or operator of a stationary combustion turbine that burns byproduct fuels. The owner or operator would be required to petition the Administrator for a site-specific standard, and, if appropriate, the Agency would conduct a notice and comment rulemaking to establish a site-specific standard. The Agency considers it appropriate to promulgate this provision because subpart KKKKa covers the HRSG that was previously covered by subpart Db when the site-specific $NO_X$ standard was adopted for industrial boilers. The Agency also solicited comment on and is finalizing amending subpart KKKK to provide a provision allowing for a site-specific $NO_X$ standard for an owner or operator of an existing stationary combustion turbine that burns byproduct fuels.

Several commenters supported finalizing a provision allowing for a site-specific $NO_X$ standard for combustion turbines burning byproduct fuels. Several commenters explained that there are environmental benefits to combusting byproduct fuels (*a.k.a.,* associated gas or opportunity fuels) in a turbine and that a case-by-case or site-specific $NO_X$ standard would encourage their use as an alternative to flaring, diesel gensets, or spark ignition gas engines, especially for byproduct fuels recovered from oil and gas drilling operations. However, one commenter noted that associated gas is not the same as "pipeline quality" natural gas and typically contains higher amounts of heavy alkanes and diluents such as carbon dioxide. According to the commenter, these substances create changes in fuel composition and increase the variability of emissions that, in turn, increase the operational variability of these types of combustion turbines. Another commenter supported amending subpart KKKK with the same rule language to maintain consistency with subpart KKKKa and added that this provision should be expanded so that facilities can request a site-specific standard for other reasons, such as using turbine exhaust to provide direct heat to a process.

Another commenter stated that the EPA's proposal to allow for a site-specific $NO_X$ standard for turbines using byproduct fuels is too broad or loosely defined. The commenter expressed concern that facilities could blend small amounts of waste gases with regular fuels to claim byproduct status while allowing for higher $NO_X$ emissions than otherwise allowed under the NSPS. To address these concerns, the commenter suggested that the final NSPS narrow the definition of "byproduct fuels" to prevent misuse, require periodic emissions testing to ensure compliance, set a minimum $NO_X$ reduction requirement as it relates to site-specific facilities using byproduct fuels, and limit the scope of this exemption so only unavoidable cases qualify.

For byproduct fuels not meeting the combustion characteristics of natural gas, DLN combustion systems have limited technical availability. In addition, byproduct fuels can contain high amounts of fuel-bound nitrogen. Since fuel-bound nitrogen forms $NO_X$ by a reaction of nitrogen bound in the fuel with oxygen in the combustion air directly (*i.e.,* is not thermally dependent), water injection also has limited technical availability to reduce fuel-bound $NO_X$. Subpart GG includes a provision for increasing the applicable $NO_X$ emission standards by up to 50 ppm based on the amount of fuel-bound nitrogen.[163] The EPA considered

[160] *See* section IV.B.2.g of this preamble for additional discussion of this reduction in the part-load threshold.

[161] *See* 42 U.S.C. 7411(a)(1), 7602(k), 7602(*l*).

[162] When determining the applicable standard for the hour in conducting this analysis, the EPA assumed the combustion turbine was operated at the hourly average capacity factor for the entire 60-minute period. However, under the rule, the part-load standard is applicable to the entire hour if the combustion turbine operates at part-load at *any point* during the hour. Note that for this analysis, hours with less than 60 minutes of operation were assigned the part-load standard regardless of the reported hourly average capacity factor.

[163] *See* 40 CFR 60.332(a)(4).

including a similar provision in subparts KKKK and KKKKa. With this provision, a turbine using water injection to reduce thermal $NO_X$ and burning byproduct fuels with high fuel-bound nitrogen must comply with a standard between 92 ppm $NO_X$ and 146 ppm $NO_X$. These emission standards are similar to the part-load standards in subparts KKKK and KKKKa, which are based on the use of diffusion flame combustion while burning fuels with low fuel-bound nitrogen. Further, for locations where byproduct fuels are available, high-purity water required for wet combustion controls is not necessarily available. In these situations, if the fuel-bound nitrogen is low, the expected emission rates would be similar to the part-load standards in subpart KKKKa. The EPA is finalizing a BSER of diffusion flame combustion for byproduct fuel-fired combustion turbines with low fuel-bound nitrogen, and diffusion flame combustion with wet combustion controls for byproduct fuel-fired combustion turbines with high fuel-bound nitrogen. Therefore, the Agency is determining in subpart KKKKa that it is appropriate to apply the same $NO_X$ standard developed for the part-load subcategory to facilities burning byproduct fuels.[164] This $NO_X$ standard recognizes the environmental benefit of reduced flaring or direct venting to the atmosphere. To address concerns about misuse of the provision, the emissions standard would be determined using the weighed emissions standard approach similar to turbines that are co-firing natural gas and non-natural gas fuels. Turbines that are only co-firing a small portion of byproduct fuel with natural gas would be subject to an emissions standard that is close to that of natural gas.

The EPA appreciates commenters' concern regarding breadth but ultimately disagrees that the provision, as proposed, was unnecessarily broad. If the NSPS is overly restrictive in the use of byproduct fuels in a combustion turbine, then those byproduct fuels would be flared or vented directly to the atmosphere. While the Agency expects that the byproduct $NO_X$ standard in subpart KKKKa will allow most types of byproducts fuels to be combusted in turbines some may still exceed the standard (*e.g.,* byproduct fuel with high fuel bound nitrogen content without available water for wet combustion controls). Therefore, to not limit the use of byproduct fuels the EPA is including the provision to allow owners or operators to petition for a site-specific standard.

e. Subcategory for HRSG Units Operating Independent of the Combustion Turbine

The affected facility under subpart KKKK (and the proposed affected facility under subpart KKKKa) includes the HRSG of CHP and combined cycle facilities. Although not common practice, it is possible that the HRSG could operate and generate useful thermal output while the combustion turbine itself is not operating. In subpart KKKK, the EPA subcategorized this type of operation and based the $NO_X$ emissions standard on the use of combustion controls for a steam generating unit under one of the steam generating unit NSPS. The EPA proposed the same BSER and emissions standard in subpart KKKKa and received no comments. In subpart KKKKa, the EPA maintains the same approach and subcategorizes operation of the HRSG independent of the combustion turbine engine with the same emissions standard as in subpart KKKK.

8. Additional Amendments to the $NO_X$ Standards

a. Form of the Standard

The form of the concentration-based $NO_X$ standards of performance in subpart KKKK is based on ppm corrected to 15 percent $O_2$ and the form of alternate output-based $NO_X$ standards is determined on a pounds per megawatt hour-gross (lb/MWh-gross) basis. Manufacturer guarantees are often reported and operating permits are often issued in ppm (corrected to an $O_2$ or $CO_2$ basis). Aligning the form of the NSPS with common practice simplifies the understanding of the emission standards and reduces the burden to the regulated community. While not the primary form of the standard, the alternate output-based form of lb/MWh-gross in subpart KKKK recognizes the environmental benefit of highly efficient generation.

In subpart KKKKa, the EPA is continuing the approach of expressing the primary form of the standard on an input basis. The EPA is including input-based $NO_X$ standards on both a ppm basis and in the form of pounds per million British thermal units (lb/MMBtu). The EPA is also finalizing optional, alternate output-based standards in both a gross- and net-output form.

There are advantages to allowing the input-based standard to be expressed on either a ppm or lb/MMBtu basis. As described in section IV.B.7.b of this preamble, co-firing hydrogen can increase the $NO_X$ emissions rate on a ppm basis when corrected to 15 percent $O_2$ while absolute $NO_X$ emissions may not significantly change. Since actual emissions to the atmosphere are the true measure of environmental impacts, the $NO_X$ emission standards in the form of lb/MMBtu are a superior measure of environmental performance when comparing emissions from different fuel types. However, throughout this document, the EPA refers to $NO_X$ emission rates using ppm for ease of comparison with performance guarantees and permitted emission rates. The standards in subpart KKKKa include both a ppm and equivalent lb/MMBtu for a natural gas-fired combustion turbine or a distillate oil-fired combustion turbine for the natural gas- and non-natural gas-fired $NO_X$ emission standards, respectively.

The EPA also proposed optional, alternate output-based $NO_X$ standards that owners or operators could elect to comply with instead of the input-based standards. Commenters opposed the output-based standards as proposed because, in their view, the values would allow greater $NO_X$ emissions than the input-based standards. The Agency disagrees that the output-based standards are less environmentally protective and is including them in subpart KKKKa. For the large high-utilization and large low-utilization subcategories, the EPA evaluated operating data and amended the efficiency value used to calculate the output-based standard. Based on available data and likely operating parameters, the EPA believes the optional output-based standards are likely to be most relevant to large high-utilization combustion turbines. The other output-based standards currently in subpart KKKK are largely maintained.

Subpart KKKK uses an assumed efficiency of 23 percent, 27 percent, and 44 percent to convert from the input to equivalent output-based standards for small, medium, and large turbines, respectively.[165] The lower efficiencies were intended to be representative of the performance of simple cycle turbines while the higher efficiency is representative of the performance of combined cycle turbines. For purposes of subpart KKKKa, the EPA reviewed the 30-operating-day efficiencies of combined cycle turbines, including all periods of operation (*i.e.,* including part-load and non-natural gas-fired hours) that have recently commenced operation. The achievable 30-operating-

[164] *See* section IV.B.7.c of this preamble for discussion of the part-load $NO_X$ standards in subpart KKKKa.)

[165] *See* 71 FR 38489.

day gross efficiencies vary from 37 to 59 percent with an average of 50 percent. The EPA also reviewed the 30-operating-day emission rates of combined cycle turbines that recently commenced operation. The demonstrated achievable emission rates vary from 0.030 lb $NO_X$/MWh-gross to 0.10 lb $NO_X$/MWh-gross. The upper range includes turbines that have maintained 4-hour full load emission rates of less than 5 ppm $NO_X$. Based on this review, for the large high-utilization combustion turbine subcategory, the EPA has determined it is appropriate to increase the efficiency used to convert the input-based standard to an equivalent output-based standard to 50 percent, and therefore the optional output-based standard is 0.12 lb $NO_X$/MWh-gross during all periods of operation.[166] (Note that part-load subcategorization is not available for combustion turbines opting to comply with the output-based standards. Among other things, the much longer 30-day averaging time makes the part-load standard less necessary.)

For the large low-utilization subcategories, the EPA uses a 38 percent efficiency to determine the optional output-based standards for the high-efficiency subcategory. The BSER analysis for this subcategory is based on the use of simple cycle turbine technology and 38 percent is the subcategorization criteria. For the low-efficiency subcategory, the average lower efficiency simple cycle turbines that recently commenced operation is 30 percent. The EPA used this value to determine the optional output-based standards for the subcategory.

As noted above, for subcategories where the input-based standard was not changed the EPA is finalizing the same optional output-based standards currently in subpart KKKK.

The EPA determines in subpart KKKKa that owners/operators can elect to comply the alternate output-based standards in either the form of gross- or net-output. Net output is the combination of the gross electrical (or mechanical) output of the combustion turbine engine and any output generated by the HRSG minus the parasitic power requirements. A parasitic load for a stationary combustion turbine represents any of the auxiliary loads or devices powered by electricity, steam, hot water, or directly by the gross output of the stationary combustion turbine that does not contribute to electrical, mechanical, or thermal output. One reason for including alternate net-output based standards is that while combustion turbine engines that require high fuel gas feed pressures typically have higher gross efficiencies, they also often require fuel compressors that have potentially larger parasitic loads than combustion turbine engines that require lower fuel gas pressures. Gross output from electrical utility units is reported to CAPD and the EPA can evaluate gross output-based emission rates directly.[167] For units calculating net-output, as an alternative to continuously monitoring parasitic loads, the EPA determines in subpart KKKKa that estimating parasitic loads is adequate and would minimize compliance costs. A calibration would be required to determine the parasitic loads at four load points: less than 25 percent load; 25 to 50 percent load; 50 to 75 percent load; and greater than 75 percent load. Once the parasitic load curve is determined, the appropriate amount would be subtracted from the gross output to determine the net output.

b. Recognizing the Benefit of Avoided Line Losses for CHP Facilities

In subpart KKKKa, the EPA recognizes the environmental benefit of generating electricity on-site by CHP facilities, which avoids line losses associated with the transmission and distribution of electricity over long distances. Actual line losses vary from location to location, but to recognize the benefit of avoided transmission and distribution losses of electricity, subpart KKKKa includes a benefit of 5 percent when determining the electric output for CHP facilities. This benefit applies only to CHP facilities where at least 20 percent of the annual output is useful thermal output. This restriction is intended to prevent CHP facilities that provide a trivial amount of thermal energy from qualifying for the 5 percent transmission and distribution benefit.

*C. $SO_2$ Emissions Standards*

For new, modified, or reconstructed stationary combustion turbines, the BSER for limiting emissions of $SO_2$ has been demonstrated to be the firing of low-sulfur fuels. Since the promulgation of the original NSPS in 1979 (subpart GG), the sulfur content of natural gas has continued to decline, and the increased stringency of this best system was reflected in an updated BSER analysis for combustion turbines when the EPA promulgated subpart KKKK in 2006, which lowered the $SO_2$ standards for this source category.

In conducting our review of the $SO_2$ standards for purposes of new subpart KKKKa, we continue to find, as proposed, that natural gas continues to be the primary fuel fired in most stationary combustion turbines, and the sulfur content of delivered natural gas in the U.S. is limited to 20 grains or less total sulfur per 100 standard cubic feet (gr/100 scf).[168] Distillate fuel oil (*i.e.,* diesel fuel) is a secondary or backup fuel for most combustion turbines, and due to EPA regulations dating back to 1993, its sulfur content must be limited by fuel producers. The sulfur content of distillate fuel oil in continental areas must not contain more than 500 parts per million by weight (ppmw) sulfur. This is considered low-sulfur diesel and is widely available as a fuel for stationary combustion turbines. However, in noncontinental areas, the availability of this low-sulfur fuel is uncertain, and fuel oil can contain as much as 4,000 ppmw sulfur. These sulfur contents are approximately equivalent to 0.05 percent by weight sulfur in continental areas and 0.4 percent by weight in noncontinental areas.

In subpart KKKKa, we are retaining the existing standards of performance from subpart KKKK. In the proposed rule, the EPA explained how the regulation and production of low-sulfur fuels has changed since the promulgation of subpart KKKK in 2006. This includes the availability in continental areas of ''pipeline'' quality natural gas with a sulfur content often less than 20 gr/100 scf. For example, depending on the U.S. region, the sulfur content of pipeline natural gas can be as low as 0.5 gr/100 scf. And for combustion turbines that potentially fire liquefied natural gas (LNG), the fuel is typically sulfur-free other than the sulfur added as an odorant for safety. Regarding diesel fuel, the sulfur content has also been reduced over time, generally in reaction to the promulgation of increasingly stringent diesel production standards for on-road and nonroad vehicles, locomotives, and certain types of marine vessels.[169] Today, ultra-low sulfur diesel (ULSD) that is limited to 15 ppmw is produced and available to combustion turbine facilities in continental areas. Therefore, in the proposal, we acknowledged that pipeline natural gas and ultra-low sulfur diesel (ULSD) are available fuels that can be fired in stationary combustion turbines in continental areas and solicited comment on the extent of the

[166] The output-based emissions standard is scaled by a factor of 1.4 for non-natural gas fuels.

[167] Net output is not reported to CAMPD.

[168] *See generally* 40 CFR part 72; *see also* 58 FR 3650 (Jan. 11, 1993).

[169] *See* 69 FR 38958 (June 29, 2004).

current use of ULSD at affected facilities, including information on the availability of ULSD in both continental and noncontinental areas.

Commenters stated that natural gas remains the primary fuel fired in most stationary combustion turbines, and the burning of distillate fuel oil is a secondary or backup/emergency fuel in many cases. However, reliable access to ULSD in certain areas remains questionable, as does documented information about its consistent use in non-utility sectors that operate stationary combustion turbines. Therefore, for purposes of subpart KKKKa, the EPA does not have sufficient information to support a determination that lower sulfur fuels than those we identified in 2006 are the BSER or to amend the associated $SO_2$ standards relative to subpart KKKK. The EPA notes that owners or operations of stationary combustion turbines typically use natural gas and fuel oil as delivered without additional processing. Technically there are limited viable options for end users to remove additional sulfur, and even if the technology was viable, the costs would be high. Moreover, while most of the pipeline and liquified natural gas available in the continental U.S. may contain less than 20 gr/scf sulfur, demonstrations of compliance with the $SO_2$ standard in the NSPS may be based on the use of tariff sheets. Setting an $SO_2$ standard that cannot use tariff sheets for the initial and ongoing compliance determinations would require site-specific performance testing. These tests could be costly when proper sampling is accounted for, with limited to no environmental benefit, given the already-very-low amount of sulfur in the typical fuel supply. Therefore, to align the $SO_2$ standards with the lower sulfur content of natural gas and ULSD in continental areas, the allowable sulfur content in tariff sheets would also need to be updated, or an exemption would need to be established for owners or operators of combustion turbines burning pipeline quality natural gas or LNG. Such impacts and alternatives would need to be considered when weighing the potential cost of compliance against potential environmental benefits. Based on this review, the EPA maintains that, as in subpart KKKK, limiting burning to low-sulfur fuels continues to be the BSER for $SO_2$ emissions from new, modified, or reconstructed stationary combustion turbines, regardless of the rated heat input, size, or utilization of the turbine. Accordingly, the application of this BSER is reflected in the $SO_2$ standards in subpart KKKKa, which are identical to those promulgated in subpart KKKK and are the same for all turbines.

Specifically, an affected source may not cause to be discharged into the atmosphere from a new, modified, or reconstructed stationary combustion turbine any gases that contain $SO_2$ in excess of 110 ng/J (0.90 lb/MWh) gross energy output or 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input. The EPA continues to recognize that low-sulfur fuels may be less available on islands and other offshore areas. For turbines located in noncontinental areas (including offshore turbines), an affected source may not cause to be discharged into the atmosphere any gases that contain $SO_2$ in excess of 780 ng/J (6.2 lb/MWh) gross energy output or 180 ng $SO_2$/J (0.42 lb $SO_2$/MMBtu) heat input.

The EPA expects no additional $SO_2$ emissions reductions based on the standards in subpart KKKKa. Although the EPA anticipates that the demand for electric output from stationary combustion turbines in the power and industrial sectors will increase during the next 8 years, the Agency does not expect significant increases in $SO_2$ emissions from the sector prior to the next CAA-required review of the NSPS. The EPA also does not expect any adverse energy impacts from the $SO_2$ standards in subpart KKKKa. All affected sources can comply with the rule without any additional controls, and the BSER and standards have not changed from subpart KKKK in 2006.

In terms of compliance with subpart KKKKa, the use of low-sulfur fuels may be demonstrated by using the fuel quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract, or through representative fuel sampling data that show that the potential sulfur emissions of the fuel do not exceed the standard. This is consistent with the monitoring and reporting requirements in subpart KKKK.

### *D. Consideration of Other Criteria Pollutants*

In the proposal, the EPA discussed whether there was any need to establish standards of performance for criteria pollutants beyond $NO_X$ and $SO_2$, including for CO and particulate matter (PM). Although such consideration of additional criteria pollutants is not required by CAA section 111(b)(1)(B) as part of the review of existing standards of performance for particular air pollutants, the EPA has authority to regulate additional air pollutants when doing so is consistent with CAA section 111. As in the proposed rule, the EPA does not believe that standards of performance for CO or PM are necessary for this source category at this time but will continue to consider these topics.

#### 1. Carbon Monoxide

Carbon monoxide is a product of incomplete combustion when there is insufficient residence time at high temperature, or incomplete mixing to complete the final step in fuel carbon oxidation. Turbine manufacturers have significantly reduced CO emissions from combustion turbines by developing lean premix technology, which is incorporated into most current turbine designs. Lean premix combustion not only produces lower $NO_X$ than diffusion flame technology but also lowers CO and volatile organic compounds (VOC). In the 2005 NSPS proposal, the EPA determined that ''with the advancement of turbine technology and more complete combustion through increased efficiencies, and the prevalence of lean premix combustion technology in new turbines, it is not necessary to further reduce CO in the proposed rule,'' and the EPA retained its view that no CO emission limitation need be developed for the combustion turbine NSPS.[170]

#### 2. Particulate Matter

Particulate matter (PM) emissions from combustion turbines result primarily from carryover of noncombustible trace constituents in the fuel. Particulate matter emissions are negligible with natural gas firing due to the low sulfur content of natural gas. Emissions of PM are only marginally significant with distillate oil firing because of the low ash content and are expected to decline further as the sulfur content of distillate oil decreases due to other regulatory requirements as discussed previously. As such, the EPA retains its view that no PM emission limitation need be developed for the combustion turbine NSPS.

### *E. Additional Amendments*

#### 1. Clarification of Fuel Analysis Requirements for Determination of $SO_2$ Compliance

The EPA is adding rule language in subpart KKKKa to clarify the intent of the rule in that if a source elects to perform fuel sampling to demonstrate compliance with the $SO_2$ standard, the initial test must be conducted using a method that measures multiple sulfur compounds (*e.g.,* hydrogen sulfide, dimethyl sulfide, carbonyl sulfide, and thiol compounds). Alternate test procedures can be used only if the

[170] 70 FR 8314, 8320–21 (Feb. 18, 2005).

measured sulfur content is less than half of the applicable standard. In addition, subpart KKKKa allows fuel blending to achieve the applicable $SO_2$ standard. Under the rule language, an owner or operator of an affected facility may burn higher sulfur fuels if the average fuel fired meets the applicable $SO_2$ standard at all times. Finally, the primary method of controlling emissions is through selecting fuels containing low amounts of sulfur or through fuel pretreatment operations that can operate at all times, including periods of startup and shutdown as discussed below in section IV.F.

2. Expanding the Application of Low-Btu Gases

For stationary combustion turbines combusting 50 percent or more biogas (based on total heat input) per calendar month, subpart KKKK established a maximum allowable $SO_2$ emissions standard of 65 ng $SO_2$/J (0.15 lb $SO_2$/MMBtu) heat input. This standard was set to avoid discouraging the development of energy recovery projects that burn landfill gases to generate electricity in stationary combustion turbines.[171] Stationary combustion turbine technologies using other low-Btu gases are also commercially available. These technologies can burn low-Btu content gases recovered from other activities, such as steelmaking (*e.g.,* blast furnace gas and coke oven gas) and coal bed methane. Like biogas, substantial environmental benefits can be achieved by using these low-Btu gases to fuel combustion turbines instead of flaring or direct venting to the atmosphere. Therefore, in subparts KKKK and KKKKa, the EPA is amending and expanding the application of the existing 65 ng $SO_2$/J (0.15 lb $SO_2$/MMBtu) heat input emissions standard to include stationary combustion turbines combusting 50 percent or more (on a heat input basis) any gaseous fuels that have heating values less than 26 megajoules per standard cubic meter (MJ/scm) (700 Btu/scf) per calendar month.

To account for the environmental benefit of productive use and simplify compliance for low-Btu gases, the Agency considers it appropriate to base the $SO_2$ standard on a fuel concentration basis as an alternative to a lb/MMBtu basis. The original proposed subpart KKKK standard for $SO_2$ was based on the sulfur content in distillate oil and included a standard of 0.05 percent sulfur by weight (500 ppmw).[172] In general, emission standards are applied to a gaseous mixture by volume (parts per million by volume (ppmv)), not by weight (ppmw). Basing the standard on a volume basis would simplify compliance and minimalize burden to the regulated community. Therefore, the EPA includes in subparts KKKK and KKKKa a fuel specification standard of 650 mg sulfur/scm (or 28 gr sulfur/100 scf) for low-Btu gases. This is approximately equivalent to a standard of 500 ppmv sulfur and is in the units directly reported by most test methods.

3. Amendments To Simplify NSPS

This rulemaking includes some additional amendments for subparts KKKK and KKKKa that are intended to simplify the regulatory burden.

a. Compliance Demonstration Exemption for Units Out of Operation

The EPA includes in subpart KKKKa, and is amending in subpart KKKK, that units that have been out of operation for 60 days or longer at the time of a required performance test are not required to conduct the performance test until 45 days after the facility is brought back into operation, or until after 10 operating days, whichever is longer. The EPA concludes that it is not appropriate to require an affected facility that is not currently in operation to start up for the sole purpose of conducting a performance test to demonstrate compliance with the NSPS.

Similarly, owners or operators of a combustion turbine that has operated 50 hours or less since the previous performance test was required to be conducted can request an extension of the otherwise required performance test from the appropriate EPA Regional Office until the turbine has operated more than 50 hours. This provision is specific to a particular fuel, and an owner or operator permitted to burn a backup fuel, but that rarely does so, can request an extension on testing on that particular fuel until it has been burned for more than 50 hours.

b. Authorization of a Single Emissions Test

For both subparts KKKKa and KKKK, we are finalizing the availability of a streamlined emissions test procedure for groups of no more than five similar stationary combustion turbines at a single source under common ownership. Such units (or ''affected facilities'') may not be equipped with SCR and use dry combustion control equipment. Specifically, for any given calendar year, the Administrator or delegated authority may authorize a single emissions test as adequate demonstration for up to five units of the same combustion turbine model and using the same dry combustion control technology, so long as: (1) the most recent performance test for each affected facility shows that performance of each affected facility is 75 percent or less of the applicable emissions standard; (2) the manufacturer's recommended maintenance procedures for each turbine and its control device are followed; and (3) each affected facility conducts a performance test for each pollutant for which it is subject to a standard at least once every 5 years.

DLN combustion results in relatively stable emission rates. Furthermore, the DLN combustor is a fundamental part of a combustion turbine, and if similar maintenance procedures are followed, the Agency concludes that emission rates will likely be comparable between combustion turbines of the same make and model. Therefore, the additional compliance costs associated with testing each affected facility (*i.e.,* each individual combustion turbine) are not needed to ensure emissions standards are being met, under the conditions specified.

c. Verification of Proper Operation of Emission Controls

Turbine engine performance can deteriorate with operation and age. Operational parameters need to be verified periodically to ensure proper operation of emission controls. Therefore, the EPA is finalizing a requirement in subpart KKKKa that facilities using the water- or steam-to-fuel ratio as a demonstration of continuous compliance with the $NO_X$ emissions standard to verify the appropriate ratio or parameters at a minimum of once every 60 months. The Agency concludes this would not add significant burden since most affected facilities are already required to conduct performance testing at least every 5 years through title V requirements or other State permitting requirements.

d. Compliance for Multiple Turbine Engines With a Single HRSG

The previous NSPS (subpart KKKK) does not state how multiple combustion turbine engines that are exhausted through a single HRSG would demonstrate compliance with the $NO_X$ standards. Therefore, the EPA includes procedures in subpart KKKKa for demonstrating compliance when multiple combustion turbine engines are exhausted through a single HRSG and when steam from multiple combustion turbine HRSGs is used in a single steam turbine. Subpart KKKK is being amended to include the same procedures.

[171] *See* 74 FR 11858 (Mar. 20, 2009).

[172] *See* 70 FR at 8319–20.

Furthermore, subpart KKKK requires approval from the permitting authority for any use of the 40 CFR part 75 $NO_X$ monitoring provisions in lieu of the specified 40 CFR part 60 procedures, but the Agency's review concludes that approval is an unnecessary burden for facilities using combustion controls only. Therefore, the EPA includes in subpart KKKKa and is amending subpart KKKK to allow sources using only combustion controls to use the $NO_X$ monitoring in 40 CFR part 75 to demonstrate continuous compliance without requiring prior approval. However, if the source is using post-combustion control technology (*i.e.,* SCR) to comply with the requirements of the NSPS, then approval from the delegated authority is required prior to using the 40 CFR part 75 CEMS procedures instead of the 40 CFR part 60 procedures.

e. System Emergency

The EPA determines it is appropriate to add a provision to subpart KKKKa clarifying the calculation of utilization levels when turbines are operated for ''system emergencies.'' Operation during system emergencies would not be included when determining the utilization-based subcategorization. In addition, for owners or operators that elect to comply with the mass-based standards, emissions during system emergencies would not be included when determining 12-calendar-month emissions.[173] The Agency concludes that this subcategorization approach is necessary to provide flexibility, maintain system reliability, and minimize overall costs to the sector.[174] The EPA defines system emergency in subpart KKKKa to mean periods when the Reliability Coordinator has declared an Energy Emergency Alert levels 1, 2, or 3 which should follow NERC Reliability Standard EOP–011–2 or its successor, or equivalent.[175] This provision ensures that stationary combustion turbines intended for less frequent operation are available for grid reliability purposes during grid emergencies without being subject to an emission standard that the unit might not be able to meet without an investment in additional controls.

These provisions in subpart KKKKa are like those included in other EPA rulemakings that affect facilities in the power sector, such as in *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units* in 2015, and in the Carbon Pollution Standards promulgated in May 2024.[176]

f. Exemptions Included From Subpart GG

The EPA included exemptions for combustion turbines used in certain military applications and firefighting applications from the standards of performance for stationary gas turbines in 40 CFR part 60, subpart GG.[177] The EPA is finalizing including these exemptions from subpart GG in subparts KKKK and KKKKa. The exemptions include military combustion turbines for use in other than a garrison facility, military combustion turbines installed for use as military training facilities, and firefighting combustion turbines. These combustion turbines only operate during critical situations.

4. Alternative Mass-Based $NO_X$ Standards

The EPA solicited comment on and is finalizing short-term and long-term mass-based $NO_X$ standards in subpart KKKKa as an optional alternative to the input- and output-based $NO_X$ standards for stationary combustion turbines. Owners or operators can choose to comply with both a short-term, 4-operating-hour rolling mass-based $NO_X$ standard and a long-term, 12-calendar-month rolling mass-based $NO_X$ standard. The optional, alternative mass-based $NO_X$ standards are designed to provide regulatory flexibility and potentially reduce compliance burden.

The implementation of mass-based $NO_X$ standards is more straightforward than for the input- and output-based standards because there is no consideration of separate standards for full- and part-load hours. Mass-based standards are a better indicator of environmental impact because, in subpart KKKKa, mass-based standards are based on total $NO_X$ emitted by the turbine. In addition, mass-based standards recognize the environmental benefit of efficient generation and provide a regulatory incentive for owners or operators of new combustion turbines to purchase the most efficient turbine designs.

The short-term, 4-operating-hour rolling mass-based standard is 0.83 lb $NO_X$/MW-rated output and the long-term, 12-calendar-month rolling mass-based standard is 0.48 tons $NO_X$/MW-rated output when combusting natural gas. As noted in the proposed rule, the 4-operating-hour rolling mass-based $NO_X$ standard is calculated based on the short-term $NO_X$ emissions from large low-utilization combustion turbines with a BSER of combustion controls; the 12-calendar-month rolling mass-based $NO_X$ standard is calculated based on the long-term $NO_X$ emissions from large high-utilization combustion turbines with a BSER of combustion controls with SCR.[178]

For owners or operators that elect to comply with the NSPS according to the 4-operating-hour and 12-calendar-month rolling mass-based $NO_X$ standards, the individual combustion turbine is not subject to the input-based $NO_X$ emission standards in table 1 of subpart KKKKa or subcategorization according to its 12-calendar-month capacity factor.[179] Instead, the combustion turbine is subject to the same 4-operating-hour rolling mass-based $NO_X$ emissions standard regardless of the actual utilization in addition to the 12-calender-month rolling mass-based $NO_X$ standard. The EPA discussed in the proposed rule that an optional, alternative short-term rolling mass-based $NO_X$ emission standard functions as an alternative to the 4-operating-hour input-based low-utilization $NO_X$ standard. The 4-operating-hour rolling mass-based $NO_X$ emission standard ensures the use of combustion controls at all times. Likewise, the 12-calendar-month rolling mass-based $NO_X$ emission standard functions as an alternative to the 4-operating-hour input-based high-utilization $NO_X$ standard. The 12-calendar-month rolling mass-based $NO_X$ standard ensures that high-utilization combustion turbines achieve greater $NO_X$ reductions with advanced

[173] *See* discussion of the optional, alternative mass-based $NO_X$ emission standards in section IV.E.4 of this preamble. During system emergencies the owner/operator of a combustion turbine complying with the mass-based standard still would be subject to a 4-hour emissions standard of 0.83 lb $NO_X$/MW-rated output or the current hourly emissions rate necessary to comply with the 12-calendar month emissions standard of 0.48 tons $NO_X$/MW-rated output, whichever is more stringent. For example, if a combustion turbine operated for 4,000 hours prior to the system emergency the 4-hour emissions standard during the system emergency would be 0.24 lb $NO_X$/MW-rated output.

[174] *See* 80 FR 64612 (Oct. 23, 2015) and 89 FR 39914–15 (May 9, 2024).

[175] The EPA determines it necessary to add ''or equivalent'' for areas not covered by NERC Reliability Standard EOP–011–2, for example Puerto Rico. The definition therefore differs slightly from the definition that had been promulgated in subpart TTTTa.

[176] *See* 40 CFR 60.5580 and 60.5580a. *See also* 40 CFR part 60, subparts TTTT and TTTTa.

[177] *See* 40 CFR 60.332(g).

[178] The short- and long-term mass-mased $NO_X$ standards are most relevant to combustion turbines where the low-utilization and high-utilization input-based (or output-based) emission standards vary significantly.

[179] The optional output-based $NO_X$ standards would also not be applicable.

combustion controls or combustion controls with SCR.

Some commenters disagreed with the optional, alternative mass-based $NO_X$ standards being the primary $NO_X$ standards in subpart KKKKa. The commenters stated that such mass-based standards could restrict the use of high-utilization, simple cycle combustion turbines as well as the operation of combustion turbines at part load. While the EPA agrees that a mass-based $NO_X$ standard is not appropriate as the primary $NO_X$ standard for this source category, it increases regulatory flexibility and could reduce regulatory compliance burden for certain owners or operators of combustion turbines. For example, some permits for combustion turbines include annual mass limitations and EGUs in the utility sector are often subject to emissions trading programs. Optional, alternative mass-based $NO_X$ standards can reduce compliance burden for owners or operators of these turbines. Therefore, alternative, mass-based $NO_X$ standards are included as a compliance option in subpart KKKKa.

In establishing appropriate mass-based $NO_X$ standards, the Agency considered the hourly standards that would otherwise be applicable. In subpart KKKKa, owners or operators of all new natural gas-fired combustion turbines operating at full load that comply with the input-based $NO_X$ standard are subject to a 4-operating-hour standard of no more than 25 ppm (0.092 lb $NO_X$/MMBtu).[180] The maximum hourly mass-based emissions of $NO_X$ can be determined according to this input-based $NO_X$ emissions standard and the design efficiency of the turbine. Further, the maximum mass-based $NO_X$ emissions rate can be normalized based on the design rated output of the turbine.[181] Similar to input-based standards, while the absolute allowable $NO_X$ emissions are determined according to the size of the turbine, the emissions standard is not. Based on reported design efficiencies and $NO_X$ emission rate guarantees, the EPA determined the design mass-based $NO_X$ emission rates of available new simple cycle turbines. The maximum hourly design mass-based $NO_X$ emissions rate of a large turbine meeting the full load, input-based emissions standard is 0.83 lb $NO_X$/MW-rated output.[182] Therefore, in subpart KKKKa, the EPA is finalizing a 4-operating-hour emissions standard of 0.83 lb $NO_X$/MW-rated output when firing natural gas. For example, a turbine with a 100 MW rated output at design conditions could comply with the 4-operating-hour standard if the cumulative emissions are maintained at or below 332 lb $NO_X$ (83 lb $NO_X$/h over a 4-hour period). Similarly, the 4-operating-hour mass-based emissions standard for a turbine with a 200 MW rated design output is 664 lb $NO_X$. The corresponding emissions standard for non-natural gas fuels is 1.5 lb $NO_X$/MW-rated output.[183] The objective of the 4-operating-hour standard is to establish an emissions standard based on the use of the BSER for low-utilization turbines (*i.e.,* combustion controls) and a more stringent standard cannot be established without restricting the use of a turbine model beyond what was determined as the BSER for low-utilization turbines.

As the Agency has noted, a challenge of establishing standards of performance for combustion turbines is that emission rates increase at lower loads. In the NSPS, the EPA addresses this issue for input-based $NO_X$ standards by subcategorizing turbine operating hours as either full-load or part-load hours. A lower numeric $NO_X$ standard (*e.g.,* 25 ppm) applies during operation at full load and a higher numeric $NO_X$ standard (*e.g.,* 96 ppm) is applicable during hours of operation at part load. The relationship between the emissions and load is complex and the Agency must balance the stringency of the full-load emissions standard and the full-load threshold and the part-load standard.[184] Since the same 4-operating-hour mass-based $NO_X$ standard applies during all periods of operation (*i.e.,* hours are not subcategorized as full- or part-load) and the relative stringency of the input-based and mass-based standards varies with the load of the turbine. At the base load rating of the turbine, the mass-based standard and the input-based standard (*i.e.,* 25 ppm $NO_X$) are essentially equivalent. When the turbine is operating above the base load rating (*e.g.,* during periods of operation at cold ambient conditions), the mass-based standard is more stringent, and compliance requires a lower input-based emissions rate. Consequently, turbines that are not able to reduce emissions below 25 ppm $NO_X$ might not be able to operate above the base load rating of the turbine. When the turbine is operated between 70 and 100 percent of the base load rating (*e.g.,* at full load but below the base load rating) the input-based standard is theoretically more stringent. However, combustion control guarantees extend to 70 percent of the base load rating or lower and owners or operators are not able to adjust the operation of DLN systems, and, in practice, compliance with the mass-based standard would not result in an increase in $NO_X$ emissions during operation between 70 and 100 percent of the base load rating.

During part-load operation, the BSER is diffusion flame combustion for both high- and low-utilization turbines. At 70 percent of the base load rating (the part-load threshold), the input-based emission standard is 3.8 times higher than the full-load input-based emissions standard, and the allowable mass-based emissions are 2.7 times higher than the allowable mass-based $NO_X$ emissions for a natural gas-fired turbine operating at full load.[185] This is difficult to avoid using the input-based $NO_X$ standard since the part-load standard includes all periods of operation at part load, including periods of startup and shutdown, and an achievable emissions standard has to account for all periods of operation when the $NO_X$ standard is applicable. While the part-load emission

[180] Large high-utilization combustion turbines are subject to an emissions standard of 25 ppm $NO_X$ when the HRSG is bypassed regardless of the efficiency of the turbine engine.

[181] The hourly design mass-based $NO_X$ emissions standard is calculated by multiplying the input-based emissions rate (lb $NO_X$/MMBtu) by the base load rating of the turbine (MMBtu/h). The product is the design output of the turbine in lb $NO_X$/h. The design output can be normalized to the rated output of the turbine by dividing the design output (lb $NO_X$/h) by the rated output of the turbine (MW). This produces units of lb $NO_X$/MW*h, but the hour in the denominator is eliminated when the value is multiplied by an hour. This results in a mass-based emissions standard of lb $NO_X$/MW-design rated output. Numerically this value is the same as the value of the design output-based emissions rate, which is calculated by multiplying the input-based emissions rate (lb $NO_X$/MMBtu) by 3.412 MMBtu/MWh and diving the product by the efficiency (in HHV) of the turbine.

[182] For large low-utilization combustion turbines, the mass-based $NO_X$ emissions standard depends on the efficiency of the turbine. The maximum hourly design emissions rate varies between 0.31 and 0.37 lb $NO_X$/MW-rated output for large lower efficiency turbines with 9 ppm $NO_X$ guarantees to 0.79 and 0.83 lb $NO_X$/MW-capacity for large higher efficiency turbines with 25 ppm $NO_X$ guarantees. While combined cycle turbines would use combustion controls with SCR to comply with the high-utilization standard, hours when the HRSG is bypassed would be subcategorized. The input-based emissions standard for these hours is 25 ppm $NO_X$ without any efficiency requirement of the turbine engine itself. The design emissions rate for these turbines could be as high as 1.0 including only the output from the turbine engine. When the output of the steam turbine is included, the maximum design emissions rate is 0.68 lb $NO_X$/MW-rated output.

[183] The non-natural gas standard was calculated using an input-based emissions rate of 42 ppm $NO_X$ (0.16 lb $NO_X$/MMBtu) and an efficiency of 30.5 percent. This represents the emissions rate that is achievable for all large simple cycle turbines in compliance with the input = based non-natural gas standard.

[184] *See* 89 FR 101320 (Dec. 13, 2024).

[185] The comparisons are done assuming a full load standard of 25 ppm $NO_X$ and a part-load standard of 25 ppm $NO_X$. The part load input-based emissions standard is 19 times higher than the 5 ppm $NO_X$ standard.

standards are significantly higher than the full-load emission standards, the absolute hourly emissions do not vary as much between part-load and full-load hours.[186] Since the mass-based standards are not subcategorized for part-load operation they are more environmentally protective when turbines are operating between approximately 25 and 70 percent of the base load rating. For example, the input-based part-load $NO_X$ emissions standard for large turbines is 96 ppm. For a 100 MW simple cycle turbine, the allowable hourly emission rates when complying with the input-based, part-load $NO_X$ emissions standard are 220 lb/h and 80 lb/h at 70 percent and 25 percent of the base load rating, respectively. The mass-based $NO_X$ emissions standard is 83 lb/h regardless of the load of the turbine. At these loads, demonstrating compliance with the mass-based standard requires operating at an input-based $NO_X$ emissions rate that is lower than the NSPS input-based $NO_X$ emissions standard. Turbines rarely operate at less than 25 percent of the base load rating, and most part-load emissions occur between 25 and 70 percent of the base load rating. Therefore, the optional, alternative mass-based $NO_X$ standard offers superior environmental protection compared to the input-based standards by recognizing the environmental benefit of reducing emissions below what is required by the input-based $NO_X$ emissions standard. Mass-based standards also eliminate any potential regulatory incentive to switch to part-load operation so that the higher part-load, input-based $NO_X$ standard is applicable during that hour.

The 12-calendar-month mass-based standard functions as an alternative to the 4-operating-hour input-based high-utilization standard and ensures that high-utilization turbines achieve greater reductions in $NO_X$ based on a BSER of combustion controls with SCR. In subpart KKKKa, new high-utilization natural gas-fired turbines operating at full load and complying with the input-based $NO_X$ emissions standard are subject to a 4-operating-hour emissions standard of 5 ppm. Like the 4-operating-hour standard, the maximum 12-calendar-month mass-based $NO_X$ emissions of a turbine can be determined based on the input-based emissions standard and the design efficiency of the turbine. Based on reported design efficiencies and using an input-based $NO_X$ emissions rate of 5 ppm, the EPA determined the average 12-calendar-month design mass-based $NO_X$ emission rates of new large combined cycle turbines to be 0.52 ton $NO_X$/MW-rated output and range from 0.48 to 0.60 ton $NO_X$/MW-rated output. At a constant, input-based emissions rate, the potential annual $NO_X$ emissions (when corrected to the design rated output) is strictly a function of the design efficiency—more efficient turbines have lower design mass-based emission rates. The EPA considered, but rejected, using these values to set the 12-calendar-month mass-based $NO_X$ emissions standard. A 4-operating-hour average accounts for short-term spikes in emissions, and on a 12-calendar-month basis, the EPA projects that high-utilization turbines will emit at a rate of 4 ppm $NO_X$. The EPA, therefore, used 4 ppm $NO_X$ when determining the 12-calendar-month mass-based $NO_X$ emissions standard. Based on design efficiencies, the average maximum 12-calendar-month mass-based emissions rate of large, combined cycle turbines is 0.42 ton $NO_X$/MW-rated output and range from 0.38 to 0.48 ton $NO_X$/MW-rated output. Therefore, the 12-calendar-month mass-based $NO_X$ standard is 0.48 tons $NO_X$/MW-rated output. A turbine with a 400 MW rated output at design conditions could comply with the 12-calendar-month standard if the cumulative $NO_X$ emissions are maintained at or below 192 tons over each rolling 12-calendar-month period. Setting a lower standard would restrict turbine models beyond what was determined to be the BSER (*i.e.,* combustion controls with SCR) for high-utilization turbines.[187] The corresponding mass-based $NO_X$ standard for non-natural gas-fired turbines is 0.81 tons $NO_X$/MW-rated output.[188]

Like the 4-operating-hour mass-based standard, the 12-calendar-month mass-based $NO_X$ standard is not subcategorized by full- and part-load hours. While the 12-calendar-month mass-based standard provides short-term flexibilities relative to the input-based standards for high-utilization turbines operating at full loads (*e.g.,* an owner or operator of a large high-utilization turbine operating at full load would not be in violation of the mass-based $NO_X$ emissions standard in the NSPS if a single 4-operating-hour period at full load exceeds 5 ppm $NO_X$), it is more environmentally protective over a 12-calendar-month period. Under the input-based standards, the average allowable $NO_X$ emissions rate of a large high-utilization turbine where 95 percent of the heat input is during full-load hours and 5 percent during part-load hours is 9.6 ppm $NO_X$. This is 2.4 times higher than the emissions rate used to derive the 12-calendar-month mass-based emissions rate. Even at a 12-calendar-month capacity factor of 50 percent, the allowable mass-based $NO_X$ emissions of a turbine complying with the input-based standards are higher than the allowable mass-based $NO_X$ emissions of the same turbine operating at a 12-calendar-month capacity factor of 100 percent and complying with the mass-based standards. For example, the allowable annual emissions of a 400 MW combined cycle turbine operating at a 12-calendar-month capacity factor of 50 percent and complying with the input-based standards is 228 tons $NO_X$. The same combined cycle turbine operating at a 100 percent capacity factor over a 12-calendar-month period complying with the mass-based emission standards would be limited to 192 tons of $NO_X$.

The benefits of mass-based $NO_X$ standards include recognizing the environmental benefit of efficiency—more efficient combustion turbines achieving the same input-based emissions rate (*e.g.,* lb $NO_X$/MMBtu) would be able to operate at higher capacity factors while still maintaining emissions below the annual standard. This approach also incentivizes reduced emissions during all periods of operation, including during startup and shutdown. It ensures that part-load operation is either kept to a minimum or emissions are lower than required by the NSPS so that both the 4-operating-hour and 12-calendar-month absolute mass-based $NO_X$ limits are fulfilled. The mass-based standards eliminate regulatory incentive to switch to part-load operation so that the higher part-load $NO_X$ standard is applicable during an operating hour. The mass-based standards also complement each other. As finalized, the 4-operating-hour mass-based $NO_X$ emissions standard is more stringent at 12-calendar-month

[186] Even though the concentration of $NO_X$ emissions is higher at part loads (which increases the mass emissions rate) the lower amount of fuel being combusted reduces the mass emissions rate.

[187] The most efficient combined cycle design could emit at an emission rate of 5 ppm $NO_X$ and still comply with the 12-calendar month emissions standard. To operate at a 100 percent capacity factor, owners or operators of simple cycle turbines would have to reduce the $NO_X$ emissions rate to between 2.6 ppm to 3.4 ppm depending on the efficiency of the turbine.

[188] While the EPA has determined that SCR is not the BSER for non-natural gas-fired turbines, natural gas-fired combined cycle turbines can fire distillate for short periods of time as a backup fuel. The EPA used a factor of 1.7 to determine the 12-calendar-month non-natural gas-fired mass-based standard. The 12-calendar-month standard is determined based on the relative heat inputs of natural gas and non-natural gas fuels during the 12-calendar-month period.

utilization rates of 13 percent and less. At higher utilization rates, the 12-calendar-month mass-based $NO_X$ emissions standard is more stringent. For example, the potential 12-calendar-month $NO_X$ emissions of a 100 MW simple cycle turbine operating at a 9 percent capacity factor complying with the 4-operating-hour mass-based emissions standard is approximately 33 tons $NO_X$. The corresponding 12-calendar-month mass-based $NO_X$ emissions standard is less stringent (48 tons $NO_X$). At a 20 percent utilization rate, the potential 12-calendar-month $NO_X$ emissions based on compliance with the 4-operating-hour mass-based emissions standard is 73 tons $NO_X$. The corresponding 12-calendar-month mass-based emissions standard is more stringent (48 tons $NO_X$). Further, to maintain compliance with the 12-calendar-month mass-based emissions standard, the turbine would have to emit at an input-based emissions rate of 16 ppm $NO_X$. To the extent this approach results in lower overall emissions while also avoiding the need to use SCR control technology, it provides an incentive for manufacturers to continue to improve combustion controls and to expand the operating conditions over which the combustion controls can operate.

Additional benefits include lowering compliance costs and providing flexibility to the regulated community—like conditions often included in operating permits. In addition, a 12-calendar-month mass-based $NO_X$ emissions standard recognizes the complex relationship between the choice of combustion controls (and the impact of those controls on other pollutants), the anticipated operation of the combustion turbine, and the use of SCR. The flexibility would allow the owner or operator of the combustion turbine to work with the permitting authority to determine the appropriate emissions reduction strategy for each specific project.

5. Exemption of Non-Major Sources From Title V Permitting

The EPA has decided to exempt certain lower-emitting stationary combustion turbines subject to subparts GG, KKKK, or subpart KKKKa from title V permitting requirements. CAA section 502(a) authorizes the Administrator to exempt certain sources subject to CAA section 111 (NSPS) standards from the requirements of title V if the Administrator finds that compliance with such requirements is ''impracticable, infeasible, or unnecessarily burdensome'' on such sources.[189] However, any exemption from title V permitting under this provision cannot extend to any sources that are ''major sources'' as that term is defined at CAA section 501(2).[190]

The EPA has previously established permitting exemptions under this provision for several NSPS, particularly in circumstances where the affected facilities are numerous and relatively low-emitting, the burdens and process of obtaining permits would be substantial for permitting authorities and the sources (such as numerous small businesses, farms, or residences), and where compliance with applicable standards can be assured through the manufacture or design of the equipment or facility in question.[191]

At proposal, the EPA explained that it had not determined that title V permitting is ''impracticable, infeasible, or unnecessarily burdensome'' for sources subject to subparts GG, KKKK, or KKKKa. However, the EPA discussed the statutory factors and requested comment as to whether there are circumstances in which the burdens and costs of going through title V permitting for combustion turbines would not be justified in light of the purposes of title V. The EPA specifically requested comment on whether there are appropriate size, emissions, or other characteristics that could be appropriately used to define sources that may warrant exemption under CAA section 502(a), and what specific features of these sources would justify such an exemption in light of the statutory criteria.

The EPA previously proposed a title V exemption for combustion turbines in a reconsideration proceeding concerning subparts GG and KKKK.[192] In conjunction with that proposal, the EPA prepared a memorandum in 2012 describing the proposed section 502(a) exemption from title V permitting requirements for non-major stationary combustion turbines subject to subparts GG or KKKK under the relevant statutory factors. The Agency cited to this document in the proposal in seeking comment.[193]

After considering comments, the EPA is finalizing a title V exemption for non-major combustion turbines that fall into the small and medium subcategories and the large low-utilization subcategory under subpart KKKKa and for all non-major combustion turbines under subparts GG and KKKK. For combustion turbines in these subcategories and/or under these subparts, the EPA finds that compliance with title V permitting is unnecessarily burdensome, as discussed in the 2012 Memorandum.

The EPA has developed a four-factor balancing test in determining under CAA section 502(a) whether compliance with title V is ''unnecessarily burdensome.'' These four factors are: (1) whether Title V permitting would result in significant improvements in compliance with emission standards; (2) whether Title V permitting would impose significant burdens on the area source category; (3) whether the costs are justified, taking into account potential gains; and (4) whether there are existing enforcement programs in place sufficient to ensure compliance.[194] The EPA has historically also considered whether such an exemption would adversely affect public health, welfare, or the environment.[195] In exercising the discretion conferred by statute, the Administrator considers the factors in combination, and not every factor must point in the same direction to support an exemption.

As explained in the 2012 Memorandum, the EPA has considered and balanced these factors and finds that they support granting the title V exemption for the identified non-major combustion turbines. Please refer to that memorandum for a full explanation of our reasoning.

We note that in adopting the analysis set forth in the 2012 Memorandum included in the docket as the primary rationale for this exemption, we have specifically considered whether any information or analysis in that document is out of date. The circumstances described there remain applicable. The 2012 Memorandum noted that as many as 1 in 10 new

[189] 42 U.S.C. 7661a(a).

[190] *Id.; see also id.* 7661(2).

[191] *See, e.g.,* 40 CFR 60.4200(c) (''If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart.'') and 40 CFR 70.3(b)(4)(i) (''The following source categories are exempted from the obligation to obtain a part 70 permit: All sources and source categories that would be required to obtain a permit solely because they are subject to part 60, subpart AAA—Standards of Performance for New Residential Wood Heaters.'').

[192] *See* 77 FR 52554, 52557–58 (Aug. 29, 2012).

[193] *See* 89 FR 101347; U.S. EPA, *Exemption of non-major source subject to new source performance standards for stationary gas combustion turbines under 40 CFR subpart KKKK from Title V permitting requirements* (June 2012) (EPA–HQ–OAR–2004–0490–0331) (hereinafter ''2012 Memorandum''), available in the docket.

[194] 70 FR 75320, 75323 (Dec. 19, 2005); *see U.S. Sugar Corp.* v. *EPA,* 830 F.3d 579, 647 (D.C. Cir. 2016).

[195] *See, e.g.,* 70 FR 75323.

combustion turbines may be owned by small entities, and in the EIA for this action, we identify that a comparable percentage of new affected units may be owned by small entities. *See* EIA section 5.2.2.

The EPA is not extending the title V exemption to large high-utilization combustion turbines under subpart KKKKa. We note that for the small, medium, and low-utilization subcategories, and for turbines subject to subparts GG or KKKK, combustion controls are the BSER, and these controls typically are integrated into the unit itself and come with manufacturer guarantees of $NO_X$ performance that are generally sufficient to comply with the relevant standards. Similarly, the vast majority of combustion turbines comply with the applicable $SO_2$ standards through firing low-sulfur fuels and do not need to install or operate add-on control technologies. In contrast, turbines in the large high-utilization subcategory are subject to a $NO_X$ standard that is premised on a BSER that includes SCR, which is an add-on control technology. Effective emissions control with SCR depends on continuing operational and maintenance practices, and a title V operating permit is typically appropriate to establish facility-specific conditions to ensure those practices are in place. Further, in most cases, large high-utilization turbines have sufficiently high potential to emit that they are often either individually large enough to constitute a major source, at a facility that is a major source, and/or are affected sources under acrid rain rules.[196] Because the EPA cannot extend title V permitting exemptions to major sources, there is therefore little practical effect in including such turbines within the scope of the exemption.

Many commenters generally supported finalizing a title V exemption. One commenter opposed any title V exemption for any sources on grounds that title V permitting is an important mechanism for transparency and accountability. The commenter stated that permitting authorities have strengthened permit conditions to ensure adequate monitoring and other compliance assurance requirements through the public participation process required by title V.

While the EPA recognizes the value of title V permitting, the Act clearly contemplates that title V permitting may be impracticable, infeasible, or unnecessarily burdensome in the case of smaller, lower-emitting units that are not located at major sources or constitute major sources in their own right. The commenter did not supply any information to counter with specificity the findings set forth in the 2012 Memorandum cited at proposal. The 2012 Memorandum explained, for example, that the monitoring and recordkeeping requirements of subpart KKKK (which generally are being carried over into subpart KKKKa) are sufficient to demonstrate compliance. The commenter did not offer any information that that conclusion is flawed, and the Agency continues to find that the monitoring and recordkeeping requirements in subparts KKKK and KKKKa are sufficient to demonstrate compliance.

We note that States remain free to subject all stationary combustion turbines to their operating permits programs if they so choose. Further, new source review (NSR) construction permitting generally applies and is not included in the title V exemption being finalized in this action. NSR permitting processes afford public participation. Thus, the EPA is finalizing a title V exemption for small and medium combustion turbines and large low-utilization turbines that are subject KKKKa and all turbines subject to GG and KKKK unless the units are co-located at a major source or major sources themselves.

### *F. NSPS Subpart KKKKa Without Startup, Shutdown, Malfunction Exemptions*

Consistent with *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the EPA has established standards in this rule that apply at all times. We are finalizing in subpart KKKKa a provision at 40 CFR 60.4320a(d) that overrides 40 CFR 60.8(c). In finalizing the standards in this rule, the EPA has considered startup and shutdown periods. These periods are accounted for through the adjusted emissions standards that apply during part-load operation and potentially when firing non-natural gas fuels. This approach continues the approach applied in subpart KKKK, which has, to the EPA's knowledge, worked well and has not created compliance challenges. The EPA received several adverse comments against the inclusion of 40 CFR 60.4320a(d) in subpart KKKKa, and we have responded to these comments in the response to comments document in the docket.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. Malfunctions, in contrast, are neither predictable nor routine. Instead, they are, by definition, sudden, infrequent, and not reasonably preventable failures of emissions control, process, or monitoring equipment.[197] The EPA interprets CAA section 111 as not requiring emissions that occur during periods of malfunction to be factored into development of CAA section 111 standards. Nothing in CAA section 111 or in case law requires that the EPA consider malfunctions when determining what standards of performance reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated. While the EPA accounts for variability in setting emissions standards, nothing in CAA section 111 requires the Agency to consider malfunctions as part of that analysis. The EPA is not required to treat a malfunction in the same manner as the type of variation in performance that occurs during routine operations of a source. A malfunction is a failure of the source to perform in a ''normal or usual manner'' and no statutory language compels the EPA to consider such events in setting CAA section 111 standards of performance. The EPA's approach to malfunctions in the analogous circumstances (setting ''achievable'' standards under CAA section 112) has been upheld as reasonable by the D.C. Circuit in *U.S. Sugar Corp.* v. *EPA,* 830 F.3d 579, 606–610 (2016).

### *G. Testing and Monitoring Requirements*

#### 1. Averaging Period

The $NO_X$ emission standards in existing subpart KKKK are based on a 4-hour rolling average for simple cycle turbines and a 30-operating-day average for combustion turbines with a HRSG (*e.g.,* combined cycle and CHP combustion turbines). The EPA solicited comment on finalizing a 4-hour average for all turbines, finalizing a daily standard, or finalizing a 30-operating-day standard. Some commenters supported a 4-hour standard for all turbines while others supported maintaining the 30-operating-day standard for combined cycle turbines, stating that it is necessary to address variability, periods of startup, and when the SCR has not reached the design temperature.

[196] A 200 MW combined cycle facility complying with the standards in this final rule would have an annual potential emissions rate of approximately 100 tons of $NO_X$. Affected sources under acid rain rules are required to obtain title V permits regardless of their potential emissions. *See* 42 U.S.C. 7651g.

[197] *See* 40 CFR 60.2.

For subpart KKKKa, the EPA analyzed hourly emissions data using 4-hour full-load rolling averages for both simple and combined cycle turbines. Since the analysis was done using reported 4-hour averages, the Agency disagrees with commenters that a longer averaging period is necessary to account for variability and periods of startup. As discussed in section IV.B.8.b above, periods of startup and shutdown would be considered part-load hours (if the turbine operates at less than 70 percent of the base load rating at any point during an hour, the entire hour is considered a part-load hour). The emissions standard for part-load hour is based on the use of diffusion flame combustion and not the use of combustion controls or combustion controls in combination with SCR. Further, when exhaust gases are bypassing the HRSG (*e.g.,* as may occur during startup, shutdown, or when the turbine is intentionally operated in simple cycle mode) those hours are subcategorized with an emissions standard of 25 ppm $NO_X$. The higher hourly emission standards would be blended with any full-load hours in the same 4-operating-hour period to determine a blended average for that 4-operating-hour period. The data analysis demonstrates that the emission standards in this final rule are achievable on a 4-operating-hour basis. Therefore, the EPA is finalizing in subpart KKKKa that the emission standards for all combustion turbines complying with the input-based standard (ppm or lb $NO_X$/MMBtu) would be determined on a 4-hour rolling average.

Subpart KKKK currently includes alternate output-based standards that owners or operators can elect to comply with instead of the input-based standard. The EPA proposed output-based standards, on both a gross- and net-output basis, as an alternative to the heat input-based standards. Owners or operators electing to use the output-based standards would demonstrate compliance on a 30-operating-day average. The longer averaging period is appropriate because both the $NO_X$ emissions rate on a lb $NO_X$/MMBtu basis and the efficiency of the combustion turbine can vary—increasing the overall variability. See section IV.B.8.a for further discussion of this topic.

2. Demonstrating Compliance With $NO_X$ Emissions Standards Using CEMS

All affected sources must conduct an initial performance test pursuant to 40 CFR 60.8 (and as further specified in subparts KKKK and KKKKa). Thereafter, varying monitoring and performance test methods apply depending on the type of emissions control used.

For combustion turbines using SCR or other post-combustion controls, subpart KKKKa requires that continuous compliance with the applicable $NO_X$ standard must be demonstrated with a $NO_X$ CEMS. Among other things, those $NO_X$ measurements must be used to determine and report excess emissions of $NO_X$ as well as monitor availability. In addition, if a stationary combustion turbine is equipped with a $NO_X$ CEMS, those measurements must be used to determine excess emissions. Owners or operators of combustion turbines not using post-combustion controls may elect to install a $NO_X$ CEMS as an alternative to the otherwise required monitoring methods.

For combustion turbines that do not use post-combustion controls and that do not have installed CEMS, subpart KKKKa provides two $NO_X$ monitoring approaches to demonstrate compliance depending on the nature of the combustion controls used, as described in sections IV.G.3 and IV.G.4.

3. Demonstrating Compliance With $NO_X$ eMissions Standards Without Using CEMS for Water or Steam Injection Combustion Controls

Owners or operators of affected sources that (1) use water or steam injection but not post-combustion controls and (2) elect not to use a $NO_X$ CEMS, must continuously monitor the water- or steam-to-fuel ratio of the affected source to demonstrate compliance. This requires the installation and operation of a continuous monitoring system (CMS) that monitors and records both the fuel consumption and the ratio of water- or steam-to-fuel being fired in the turbine. Owners or operators of affected combustion turbines using combustion controls that elect not to use a $NO_X$ CEMS must conduct performance testing at a minimum of once every 12 months, except as otherwise specified in 40 CFR 60.4331a(c)(2), 40 CFR 60.4333a(b)(2), and 40 CFR 60.4333a(b)(5)(v).

4. Demonstrating Compliance With $NO_X$ Emissions Standards Without Using CEMS for Non-Water or Non-Steam Injection Combustion Controls

Owners or operators of affected sources that (1) do not use water or steam injection or post-combustion controls and (2) elect not to use a $NO_X$ CEMS, must then (a) conduct performance tests according to 40 CFR 60.4400a, (b) monitor the $NO_X$ emissions rate using the Appendix E or low mass emissions methodology of 40 CFR part 75, or (c) install, calibrate, maintain, and operate an operating parameter CMS according to 40 CFR 60.4340a(b)(1)–(4).

*H. Electronic Reporting*

To increase the ease and efficiency of data submittal and data accessibility, the EPA is finalizing, as proposed, a requirement that owners or operators of stationary combustion turbine facilities subject to existing NSPS subparts GG and KKKK and subpart KKKKa submit electronic copies of initial and periodic performance test reports (including relative accuracy test audits (RATAs)), and compliance reports through the EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI). A description of the electronic data submission process is provided in the memorandum, *Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules,* available in the docket for this action. The final rule requires that performance test results be submitted in the format generated through the use of the EPA's Electronic Reporting Tool (ERT) or an electronic file consistent with the xml schema on the ERT website.[198] Similarly, performance evaluation results of CEMS that include a RATA must be submitted in the format generated through the use of the ERT or an electronic file consistent with the xml schema on the ERT website. Alternatively, electronic files consistent with the xml schema on the ERT website accompanied by all the information required by 40 CFR 60.8(f)(2) in PDF may be submitted.[199]

Specifically, the final requires that (1) for NSPS subpart GG, the reports specified in 40 CFR 60.334(k), (2) for NSPS subpart KKKK, the reports specified in 40 CFR 60.4375, and (3) for NSPS subpart KKKKa, the reports specified in 40 CFR 60.4375a, owners or operators use the appropriate spreadsheet template to submit information to CEDRI.[200] The final version of the template[s] for these

[198] *https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert.*

[199] A PDF of the full stack test report (*i.e.,* performance test report and/or RATA) may optionally be submitted as an attachment to the ERT package test data but is not required.

[200] 40 CFR 60.334(k), 60.4375, and 60.4375a also now include updated language reflecting the EPA's current report submittal procedures regarding CDX, CEDRI, ERT, and CBI.

reports will be located on the CEDRI website.[201]

Furthermore, the EPA is finalizing in subparts GG, KKKK, and KKKKa, as proposed, provisions that allow owners or operators the ability to seek extensions for submitting electronic reports for circumstances beyond the control of the facility, *i.e.,* for a possible outage in CDX or CEDRI or for a *force majeure* event, in the time just prior to a report's due date, as well as the process to assert such a claim.

*I. Other Final Amendments*

The EPA requested comment on whether it is appropriate in subpart KKKKa to divide the thermal output from district energy systems by a factor (*i.e.,* 0.95 or 0.90) that would account for the net efficiency benefits of district energy systems. The Agency received no comments on the solicitation and is finalizing a factor of 0.95, which is the same as the electric transmission and distribution factor.

*J. Effective Date and Compliance Dates*

Pursuant to CAA section 111(b)(1)(B), the effective date of the final rule requirements in subparts KKKKa, KKKK, and GG will be the promulgation date. Affected sources that commence construction, reconstruction, or modification after December 13, 2024, must comply with all requirements of subpart KKKKa no later than the effective date of the final rule or upon startup, whichever is later.

*K. Severability*

This final action contains several discrete components, which the EPA views as severable as a practical matter—*i.e.,* they are functionally independent and operate in practice independently of the other components. These discrete components are generally delineated by the section headings within section IV of this document. In general, each of the final BSER determinations and associated emissions standards for each subcategory function independently of the others, as do any differences in the rule associated with modified or reconstructed units. In addition, the several other provisions of subpart KKKKa included in this final rule (and any associated changes to subparts GG and KKKK) generally function independently of one another.

**V. Summary of Cost, Environmental, and Economic Impacts**

*A. What are the air quality impacts?*

During the period 2025–2032, the EPA estimates that approximately 44 new stationary combustion turbines per year will be installed in the U.S. and would be affected by this rule. The EPA estimates that 26 of these combustion turbines will be in the electric utility power sector. For affected combustion turbines in the electric utility power sector, the BSER in subpart KKKKa is generally consistent with the control technologies in the baseline. That is, based on data reported to the EPA, the Agency anticipates that new combined cycle facilities (including combined cycle CHP facilities) would already have plans to use controls or otherwise achieve emissions rates equivalent to the emissions standards finalized in this NSPS, though in some cases new combined cycle turbines may have to upgrade and/or operate the controls more intensively than existing counterparts to meet the NSPS requirements in subpart KKKKa. The EPA estimates that most new simple cycle combustion turbines generating electricity would be in the low-utilization subcategory and have combustion controls consistent with the standards and would not be impacted by this action. The EIA for this final rule includes additional details of EPA's methodology for estimating cost, environmental, and other economic impacts, as well as a discussion of the limitations and uncertainties.

Based on information collected as part of a separate combustion turbine NESHAP rulemaking, the EPA projects that each year approximately 10 new, modified, or reconstructed direct mechanical drive combustion turbines (*e.g.,* compressors) will be subject to the $NO_X$ standards in subpart KKKKa. However, none of these units are expected to incur increased costs because of this rule.

Table 2 below presents the projected change in $NO_X$ emissions under the final rule from 2025 to 2032. $NO_X$ emissions are a precursor to ozone and fine particulate matter.

TABLE 2—NET $NO_X$ EMISSION CHANGES IN FIRST 8 YEARS AFTER THE RULE IS FINAL

[tons]

| Year | Net annual $NO_X$ emission changes relative to baseline (tons) |
|---|---|
| 2025 | 0 to 0 |
| 2026 | 0 to 0 |
| 2027 | 41 to 88 |
| 2028 | −26 to 68 |
| 2029 | −94 to 47 |
| 2030 | −161 to 27 |
| 2031 | −229 to 5 |
| 2032 | −296 to −15 |

The range in the projected emissions changes in Table 2 is due to the uncertainty in the number of higher efficiency turbines that will be constructed in the future. See section V.C of this preamble for further discussion on this topic. We also note that there are no expected $SO_2$ reductions because of the rule. All estimates and assumptions of emissions reductions have been documented in the rulemaking docket.

*B. What are the secondary impacts?*

The requirements in subpart KKKKa are not anticipated to result in significant energy impacts. The only energy requirement is a potential small increase in fuel consumption, resulting from operating the $NO_X$ control equipment and back pressure caused by an add-on emission control device, such as an SCR. However, many entities will be able to comply with the final rule

[201] *https://www.epa.gov/electronic-reporting-air-emissions/cedri.*

without the use of add-on control devices. Because the cost of the identified BSER control technologies is a relatively small percentage of the total costs associated with building and operating combustion turbines in the various subcategories for which those technologies are BSER, the EPA does not anticipate significant secondary effects in terms of switching to other methods of electricity generation or mechanical output.

While no new installations of SCR beyond the baseline are anticipated to be required by this rule, some large high-utilization combustion turbines may need to run their SCR more to comply with the $NO_X$ emission limit. The slightly increased application of SCR for large high-utilization combustion turbines is estimated to modestly increase emissions of ammonia ($NH_3$). Therefore, subpart KKKKa is estimated to increase $NH_3$ emissions by 1 ton in 2027; 12 tons in 2028; 22 tons in 2029; 33 tons in 2030; 44 tons in 2031; and 54 tons in 2032. It should be noted that these are likely overestimates, because we assumed SCR installation as a proxy for combustion controls for industrial sources in this analysis, given the lack of data on combustion control costs. Compliance in many cases will likely be achieved through combustion controls, which would lead to reduced ammonia emissions compared to these estimates. The EPA notes that emissions may also increase generally to the extent that emissions control strategies used make a turbine less efficient and therefore result in additional utilization.

*C. What are the cost impacts?*

To comply with the requirements of this final rule, some new units will incur capital costs associated with installation of controls or upgrades to planned controls, while some units that modify or reconstruct are expected to incur some increased operating costs of their controls to meet the rule requirements. These capital costs and increased operating costs were estimated based on model plants from the DOE NETL flexible generation report.[202] For the analysis period 2025–2032, the total estimated capital cost is $13.7 million (2024$), and the operation and maintenance costs are $9.5 million (2024$). Combined, this represents a present value in 2024 of $19.4 million (2024$) and an equivalent annualized value of $2.77 million (2024$) at a 3 percent discount rate, and a present value of $15.5 million (2024$) and an equivalent annualized value of $2.59 million (2024$) at a 7 percent discount rate.

There is also a deregulatory aspect of this rule. New natural gas-fired combustion turbines in the large, low-utilization subcategory that are higher efficiency (*i.e.,* with a base load rated heat input greater than 850 MMBtu/h, utilized at a 12-calendar-month capacity factor less than or equal to 45 percent, and with a design efficiency greater than or equal to 38 percent on a HHV basis) are subject to a less stringent $NO_X$ emission limit than they otherwise would have been subject to under the previous NSPS. When subpart KKKK was promulgated in 2006, these classes of large, higher efficiency turbines did not exist. They are a newer technology that is now commercially available, and subpart KKKKa is recognizing this fact along with the environmental and economic benefits of operating higher efficiency designs at lower levels of utilization.

To account for the rule accommodating these higher efficiency turbines, we conduct an additional analysis where we compare the construction and operations of these higher efficiency turbines under the final rule to a baseline where lower efficiency turbines compliant with the 2006 $NO_X$ standards are constructed instead. How many new turbines will take advantage of this subcategory in the future is uncertain, so we assume two to four single turbines are constructed for each 5-year period beginning in 2027. Specifically, EPA has identified 28 frame-type combustion turbines that have commenced operation in the previous 5 years. One of these turbines was a large high-efficiency combustion turbine with SCR controls. An additional six large turbines completed during this period have comparable or higher utilization rates. The EPA presumes that a subset of these turbines would have considered the new large higher efficiency subcategory had it been available. Therefore, the EPA identified two to four turbines per 5-year period as a likely range for the rate of new turbines availing themselves of this higher efficiency subcategory. Although we assume that the higher efficiency turbines have more expensive capital costs, the fuel savings lead to overall cost savings for the turbine operators. The present value in 2024 of the combined capital cost and fuel savings for these turbines under the deregulatory provision is projected to be $53.2 million to $106.2 million (2024$) with an equivalent annualized value of $7.58 million to $15.2 million (2024$) at a 3 percent discount rate, and a present value of $21.5 million to $43.0 million (2024$) with an equivalent annualized value of $3.60 million to $7.19 million (2024$) at a 7 percent discount rate, where the range reflects the assumption of two to four higher efficiency turbines constructed during the analysis period.

The present value in 2024 of the net regulatory cost savings is projected to be $33.8 million to $87.0 million (2024$) with an equivalent annualized value of $4.81 million to $12.4 million (2024$) at a 3 percent discount rate, and a present value of $5.98 million to $27.5 million (2024$) with an equivalent annualized value of $1.01 million to $4.60 million (2024$) at a 7 percent discount rate, where the range again reflects uncertainty about the number of higher efficiency turbines that will be constructed during the analysis period.

*D. What are the economic impacts?*

Economic impact analyses focus on changes in market prices and output levels. If changes in market prices and output levels in the primary markets are significant enough, impacts on other markets may also be examined. Both the magnitude of costs needed to comply with a rule and the distribution of these costs among affected facilities can have a role in determining how the market will change in response to a rule.

This final rule generally requires new, modified, or reconstructed stationary combustion turbines to meet more stringent emission standards for the release of $NO_X$ into the environment than required under subparts GG or KKKK. While the units impacted by these requirements are generally expected to construct using emissions control devices that would already be compliant with the revised NSPS, some units may incur some increased costs to meet the rule requirements. These changes may result in higher costs of production for affected producers and impact broader markets these entities serve. As shown in section 2.5 of the EIA, the types of turbines affected by this rulemaking are primarily used in the power sector and in the oil and natural gas transmission sector but are located in smaller numbers in many economic sectors.

However, because the increased costs discussed in the previous section are small in comparison to the sales of the average owner of a combustion turbine, the costs of this rule are not expected to result in a significant market impact, regardless of whether they are passed on

[202] Oakes, M.; Konrade, J.; Bleckinger, M.; Turner, M.; Hughes, S.; Hoffman, H.; Shultz, T.; and Lewis, E. (May 5, 2023). *Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation.* U.S. Department of Energy (DOE). Office of Scientific and Technical Information (OSTI). Available at *https://www.osti.gov/biblio/1973266.*

through market relationships or absorbed by the firms. For more information on these impacts, please refer to the economic impact analysis in the rulemaking docket.

*E. What are the benefits?*

Combustion turbines are a source of $NO_X$ and $SO_2$ emissions. The health effects of exposure to these pollutants are briefly discussed in this section. The revised NSPS is expected to result in reductions of $NO_X$ emissions from new, modified, or reconstructed units.

The EPA is obligated to present the Agency's best scientific understanding when developing policies and regulations and to ensure the public is not misled regarding the level of scientific understanding. Historically, however, the EPA's analytical practices often provided the public with a false sense of precision and more confidence regarding the monetized impacts of fine particulate matter ($PM_{2.5}$) and ozone than the underlying science could fully support, especially as overall emissions have significantly decreased, and impacts have become more uncertain. The EPA has seen the uncertainties expand even further with the use of benefit-per-ton (BPT) monetized values. Although intended as a screening tool when full-form photochemical modeling was not feasible, the BPT approach reduces complex spatial and atmospheric relationships into an average value per ton, which magnifies uncertainty in the resulting monetized estimates. Examples of uncertainties include but are not limited to: epidemiological uncertainty (*e.g.,* concentration-response functions, mortality valuation); economic factors (*e.g.,* discount rates, income growth); and methodological assumptions (*e.g.,* health thresholds, linear relationships, spatial relationships).

However, the EPA historically provided point estimates instead of just ranges or only quantifying emissions, which leads the public to believe the Agency has a better understanding of the monetized impacts of exposure to $PM_{2.5}$ and ozone than in reality. Therefore, to rectify this error, the EPA is no longer monetizing benefits from $PM_{2.5}$ and ozone but will continue to quantify the emissions until the Agency is confident enough in the modeling to properly monetize those impacts.

Historically, the EPA estimated the monetized benefits of avoided $PM_{2.5}$- and ozone-related impacts, which accounted for most, if not all, of the monetized benefits of many air regulations—even when the regulation was not regulating $PM_{2.5}$ or ozone—within Regulatory Impact Analyses (RIAs).[203] Throughout these analyses, the EPA acknowledged significant uncertainties related to monetized $PM_{2.5}$ and ozone impacts. The EPA has and is considering various techniques for characterizing the uncertainty in such estimates, such as estimating the fraction of avoided health effects occurring at various concentration ranges, sensitivity analyses, and alternate concentration-response assumptions. Because of the significant impacts of environmental regulations on the U.S. economy, it is essential that the Agency have confidence in the estimated benefits of an action prior to utilizing these estimates in a regulatory context.

In particular, the EPA is interested in evaluating the validity of estimating the benefits of air quality improvements relative to the National Ambient Air Quality Standards (NAAQS) for $PM_{2.5}$ and ozone. These standards, which have been set at a level which the Administrator judges to be requisite to protect public health or welfare with an adequate margin of safety, are widely understood to represent the divide between clean air and air with an unacceptable level of pollution.

The limitations of the BPT approach are even more pronounced due to the compounding effects of emissions reductions typically occurring across many geographic areas simultaneously, with varying proximity to population centers; differing atmospheric transformation pathways for nitrous oxides ($NO_X$), Volatile Organic Compounds (VOCs), and secondary $PM_{2.5}$; and region-specific photochemical and meteorological conditions. Using a national BPT estimate implicitly assumes uniform marginal health benefits for each ton of reduced emissions, an assumption not supported given heterogeneity in exposure patterns and atmospheric chemistry. As more areas achieve or maintain attainment with the NAAQS, the uncertainties associated with low-concentration health effects grow, and marginal benefits become more difficult to characterize with precision.

Therefore, it may be appropriate for the EPA to separate exposures and impacts above the level of the standard from those occurring at lower ambient concentrations. The EPA will investigate this prior to estimating these impacts in a regulatory analysis even for informational purposes. The EPA will seek peer review for new methods developed from this work consistent with the OMB's Peer Review Guidance.[204]

1. Benefits of $NO_X$ Reductions

Nitrogen dioxide ($NO_2$) is the criteria pollutant that is central to the formation of nitrogen oxides ($NO_X$), and $NO_X$ emissions are a precursor to ozone and fine particulate matter.[205]

Based on many recent studies discussed in the ozone Integrated Science Assessment (ISA),[206] the EPA has identified several key health effects that may be associated with exposure to elevated levels of ozone. Exposures to high ambient ozone concentrations have been linked to increased hospital admissions and emergency room visits for respiratory problems. Repeated exposure to ozone may increase susceptibility to respiratory infection and lung inflammation and can aggravate preexisting respiratory disease, such as asthma. Prolonged exposures can lead to inflammation of the lung, impairment of lung defense mechanisms, and irreversible changes in lung structure, which could in turn lead to premature aging of the lungs and/or chronic respiratory illnesses such as emphysema, chronic bronchitis, and asthma.

Children typically have the highest ozone exposures since they are active outside during the summer when ozone levels are the highest. Further, children are more at risk than adults from the effects of ozone exposure because their respiratory systems are still developing. Adults who are outdoors and moderately active during the summer months, such as construction workers and other outdoor workers, also are among those with the highest exposures. These individuals, as well as people with respiratory illnesses such as asthma, especially children with asthma, experience reduced lung function and increased respiratory symptoms, such as chest pain and cough, when exposed to relatively low ozone levels during periods of moderate exertion.

$NO_X$ emissions can react with ammonia, VOCs, and other compounds

[203] See OMB's 2017 Report to Congress on Benefits and Costs of Federal Regulations and Agency Compliance with the Unfunded Mandates Reform Act for fuller discussion on uncertainties at *https://trumpwhitehouse.archives.gov/wp-content/uploads/2019/12/2019-CATS-5885-REV_DOC-2017Cost_BenefitReport11_18_2019.docx.pdf.*

[204] OMB Memorandum M–05–03, Memorandum for the Heads of Executive Departments and Agencies: Issuance of OMB's "Final Information Quality Bulletin for Peer Review" (2005), available at *https://www.federalregister.gov/documents/2005/01/14/05-769/final-information-quality-bulletin-for-peer-review.*

[205] Additional information is available in the ISA at *https://www.epa.gov/isa/integrated-science-assessment-isa-oxides-nitrogen-health*-criteria.

[206] *See* Ozone ISA at *https://assessments.epa.gov/isa/document/&deid=348522.*

to form $PM_{2.5}$.[207] Studies have linked $PM_{2.5}$ (alone or in combination with other air pollutants) with a series of negative health effects. Short-term exposure to $PM_{2.5}$ has been associated with premature mortality, increased hospital admissions, bronchitis, asthma attacks, and other cardiovascular outcomes. Long-term exposure to $PM_{2.5}$ has been associated with premature death, particularly in people with chronic heart or lung disease. Children, the elderly, and people with cardiopulmonary disease, such as asthma, are most at risk from these health effects.

Reducing the emissions of $NO_X$ from stationary combustion turbines can help to improve some of the effects mentioned above, either those directly related to $NO_X$ emissions, or the effects of ozone and $PM_{2.5}$ resulting from the combination of $NO_X$ with other pollutants.

2. Benefits of $SO_2$ Reductions

High concentrations of $SO_2$ can cause inflammation and irritation of the respiratory system, especially during physical activity.[208] Exposure to very high levels of $SO_2$ can lead to burning of the nose and throat, breathing difficulties, severe airway obstruction, and can be life threatening. Long-term exposure to persistent levels of $SO_2$ can lead to changes in lung function.

Sensitive populations include asthmatics, individuals with bronchitis or emphysema, children, and the elderly. PM can also be formed from $SO_2$ emissions. Secondary PM is formed in the ambient air through a number of physical and chemical processes that transform gases, such as $SO_2$, into particles. Overall, emissions of $SO_2$ can lead to some of the effects discussed in this section—either those directly related to $SO_2$ emissions, or the effects of PM resulting from the combination of $SO_2$ with other pollutants. Maintaining the standards of performance for emissions of $SO_2$ from all stationary combustion turbines will continue to protect human health and the environment from the adverse effects mentioned above.

3. Disbenefits From Increased Emissions of $NH_3$ and $NO_X$

Ammonia is a precursor to $PM_{2.5}$ formation and an increase in $NH_3$ formation may lead to an increase in $PM_{2.5}$. An increase in $PM_{2.5}$ is associated with significant mortality and morbidity health outcomes such as premature mortality, stroke, lung cancer, metabolic and reproductive effects, among others.

There are also potential $NO_X$ disbenefits associated with the use of higher efficiency combustion turbines. As previously noted, new natural gas-fired combustion turbines in the large, low-utilization subcategory that are higher efficiency (*i.e.,* with a base load rated heat input greater than 850 MMBtu/h, operating at a 12-calendar-month capacity factor less than or equal to 45 percent, and with a design efficiency greater than or equal to 38 percent) are subject to a less stringent $NO_X$ emission limit than otherwise applicable under the previous NSPS (subpart KKKK). These higher $NO_X$ emissions create disbenefits relative to the baseline with lower efficiency turbines.

## VI. What actions are we not finalizing and what is our rationale for such decisions?

The EPA is not finalizing certain proposed revisions to the NSPS for stationary combustion turbines and stationary gas turbines pursuant to CAA section 111(b)(1)(B) review.

### *A. Clarification to the Definition of Stationary Combustion Turbine*

To clarify the applicability of the definition of a stationary combustion turbine when determining whether an existing combined cycle or CHP facility should be considered ''new'' or ''reconstructed,'' the EPA proposed to amend the rule language in subpart KKKKa. In subpart KKKK, the definition of the affected source includes the HRSG and associated duct burners at combined cycle and CHP facilities.[209] The amended language was intended to clarify that the test for determining if an existing facility is a new source would be based on whether only the combustion turbine portion of the affected combined cycle/CHP facility (*i.e.,* HRSG, etc.) was entirely replaced. The reconstruction applicability determination was proposed to be based on whether the fixed capital costs of the replacement of components of the combustion turbine portion (*i.e.,* the air compressor, combustor, and turbine sections) exceeded 50 percent of the fixed capital costs of installing *only* a comparable new combustion turbine portion of the affected facility. The EPA proposed that it was appropriate for owners or operators of combined cycle and CHP facilities that entirely replace or undertake major capital investments in the combustion turbine portion of the facility to invest in emissions control equipment as well.

This specific portion of the 2024 Proposed Rule raised numerous questions and concerns in public comments and opposition to amending the definition of the source as proposed in subpart KKKKa was consistent across all sectors. Therefore, in this final action, the EPA is not finalizing any proposed revisions to the definition of stationary combustion turbines that would impact a reconstruction analysis to determine whether an existing combined cycle or CHP combustion turbine should be subject to the requirements for new sources under subpart KKKKa.

*See* the EPA's response to comments document in the docket for this rule for complete summaries of comments regarding this specific proposal and the EPA's responses.

B. Definition of Noncontinental Area

The EPA's review of low-sulfur fuels for this NSPS indicates that since subpart KKKK was promulgated, the availability of low-sulfur diesel has increased in States and territories previously defined as noncontinental areas for purposes of compliance with the $SO_2$ emission standards in subpart KKKK. As a result, in subpart KKKKa, the EPA proposed to remove Hawaii, the Commonwealth of Puerto Rico, and the U.S. Virgin Islands from the definition of noncontinental area. This proposed change would require new, modified, or reconstructed stationary combustion turbines in Hawaii, Puerto Rico, and the Virgin Islands to demonstrate compliance with the lower $SO_2$ standards in subpart KKKKa for affected sources in continental areas. The continental standards are based on fuel oil with sulfur content limited to approximately 0.05 percent sulfur by weight (500 ppmw).

Based on available information, the EPA also proposed to maintain in subpart KKKKa that Guam, American Samoa, the Northern Mariana Islands, and offshore platforms be included in the definition of noncontinental area and those locations would continue to be allowed to meet the existing standards for higher sulfur fuels. This is due to the fact these locations continue to have limited access to the same low-sulfur fuels as facilities in continental areas.

In response to the proposal, several commenters, including commenters from the State of Hawaii, opposed the removal of Hawaii, the Commonwealth of Puerto Rico, and the U.S. Virgin Islands from the definition of

[207] $PM_{2.5}$ health effects are discussed in detail in the ISA at *https://www.epa.gov/isa/integrated-science-assessment-isa-particulate-matter.*

[208] Health effects are discussed in detail in the ISA available at *https://www.epa.gov/isa/integrated-science-assessment-isa-sulfur-oxides-health-criteria.*

[209] *See* 71 FR 38483; July 6, 2006.

noncontinental area. Specifically, commenters stated that the proposal would disproportionately affect island utilities that must rely on liquid fuels and that lack the compliance options of utilities located in continental areas. The commenters also highlighted some of the regulatory precedents that exist in rules previously promulgated in the power sector in which the EPA has acknowledged the need to set more relaxed standards in Hawaii and other remote islands. The commenters also stated that an additional supporting factor for the non-continental exemption is the attainment status of Hawaii for all regulated pollutants. Another commenter stated that before proposing to determine that these locations have the same access to low-sulfur fuels as continental areas, the EPA should provide additional information to support the proposed new $SO_2$ standards for affected sources located in Hawaii, Puerto Rico, and the Virgin Islands (*i.e.,* cost effectiveness analysis). Should additional EPA analyses support the proposed new $SO_2$ standards, the EPA should include a delayed compliance date (*i.e.,* 5 years) for affected sources to use their remaining higher sulfur fuel oil supplies and to allow fuel oil suppliers time to develop reliable long-term supplies of low sulfur fuel oil to those areas.

This specific proposal raised numerous questions and concerns in public comments and opposition to amending the definition of the noncontinental areas as proposed in subpart KKKKa was consistent from affected stakeholders. Therefore, in this action, the EPA is not finalizing the proposed revisions to the definition of noncontinental area for new sources under subpart KKKKa.

### *C. Affected Facility*

The EPA requested comment on treating multiple combustion turbine engines connected to a single generator, separate combustion turbines engines using a single HRSG, and separate combustion turbine engines with separate HRSG that use a single steam turbine or otherwise combine the useful thermal output as single affected facilities. The Agency is not finalizing any changes that would treat multiple turbines as a single affected facility.

## VII. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

### *A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review*

This action is a significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket. An economic impact analysis (EIA) was prepared for this action and is available in the docket.

The EIA estimates the costs from 2025–2032 associated with the application of the BSER to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 GJ/h (10 MMBtu/h), based on the HHV of the fuel, that commence construction, modification, or reconstruction after the date of publication of the 2024 Proposed Rule in the **Federal Register**. These costs are relative to the baseline of the existing NSPS (subpart KKKK). Table 3 below provides a summary of the estimated costs associated with the application of the BSER to these new, modified, or reconstructed stationary combustion turbines and stationary gas turbines.

TABLE 3—ESTIMATED MONETIZED COSTS OF COMBUSTION TURBINES NSPS

[Millions, 2024$]

| | | 3% Discount rate | | 7% Discount rate | |
|---|---|---|---|---|---|
| | | PV | EAV | PV | EAV |
| Impacts associated with subcategories with increased stringency. | Costs | $19.4 | $2.77 | $15.5 | $2.59. |
| Impacts associated with subcategories with decreased stringency. | Avoided Costs | $53.2 to $106 | $7.58 to $15.2 | $21.5 to $43.0 | $3.60 to $7.19. |
| Net Costs | | −$87.0 to −$33.8 | −$12.4 to −$4.81 | −$27.5 to −$5.98 | −$4.60 to −$1.01. |

**Notes:** Values rounded to three significant figures. The range reflect the assumption of two to four higher efficiency turbines constructed during the analysis period.

The net benefits associated with the regulated pollutants are the net cost savings of this final action presented above in Table 3. Potential non-quantified impacts are expected from changes in $NO_X$ emissions. The EIA presents a discussion of the projected costs and benefits of this action, as well as a discussion of uncertainty and additional impacts that the EPA could not quantify or monetize.

### *B. Executive Order 14192: Unleashing Prosperity Through Deregulation*

This action is considered an Executive Order 14192 deregulatory action. Details on the estimated cost savings of this final rule can be found in EPA's analysis of the potential costs and benefits associated with this action.

### *C. Paperwork Reduction Act (PRA)*

The information collection activities in this rule have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 7810.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them. As noted in section IV.H, the template for the semiannual report for these subparts will be on the CEDRI website.[210]

The EPA is finalizing amendments to the NSPS for stationary combustion turbines and stationary gas turbines to establish size-based subcategories for new, modified, or reconstructed stationary combustion turbines, update $NO_X$ standards of performance for certain stationary combustion turbines and address specific technical and editorial issues to clarify the existing regulations. The EPA is also finalizing amendments to add electronic reporting requirements for submittal of certain reports and performance test results.

This information will be collected to assure compliance with 40 CFR part 60, existing subparts GG, KKKK, and new subpart KKKKa. The total estimated burden and cost for reporting and recordkeeping due to these amendments

[210] *See https://www.epa.gov/electronic-reporting-air-emissions/cedri.*

are presented here and are not intended to be cumulative estimates that include the burden associated with the requirements of the existing 40 CFR part 60, subparts GG and KKKK, and new 40 CFR part 60, subpart KKKKa. The ICR reflects both the total burden for subject units to comply with GG, KKKK, and KKKKa and the incremental burden associated with the requirements of these final amendments.

- *Respondents/affected entities:* Owners or operators of new, modified, or reconstructed stationary combustion turbines.
- *Respondent's obligation to respond:* Mandatory.
- *Estimated number of respondents:* 5.
- *Frequency of response:* Semi-annual.
- *Total estimated burden:* 310 hours per year. Burden is defined at 5 CFR 1320.3(b).
- *Total estimated cost:* $36,000 per year, includes $0 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

*D. Regulatory Flexibility Act (RFA)*

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. In making this determination, the EPA concludes that the impact of concern for this rule is any significant adverse economic impact on small entities and that the Agency is certifying that this rule will not have a significant economic impact on a substantial number of small entities because the rule relieves regulatory burden. The small entities subject to the requirements of this action include small businesses and small governmental entities. The rule relieves regulatory burden by modifying several provisions that could impact small entities. Amendments to simplify the NSPS are discussed in section IV.E.3 of this preamble, and other flexibilities in this final rule, including an exemption from title V permitting for certain non-major combustion turbines, are also discussed in section IV.E. While not quantified, these amendments are expected to result in cost savings for affected entities. In addition, section V.C of this preamble discusses cost savings associated with the less stringent $NO_X$ emission limit for certain large, higher efficiency turbines. Because this is a relatively new technology, the EPA is unable to estimate the number of small entities that will experience regulatory relief under this provision. For this reason, the EIA only considers potential costs as a conservative approach. For all small entities projected to experience economic impact, those impacts are estimated to be less than one percent of revenues.

*E. Unfunded Mandates Reform Act (UMRA)*

This action does not contain an unfunded mandate of $100 million (adjusted annually for inflation) or more (in 1995 dollars) as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The costs involved in this action are estimated not to exceed $187 million in 2024$ ($100 million in 1995$ adjusted for inflation using the GDP implicit price deflator) or more in any one year.

*F. Executive Order 13132: Federalism*

This action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

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

This action does not have Tribal implications as specified in Executive Order 13175. The EPA is not aware of any stationary combustion turbine owned or operated by Indian Tribal governments. However, if there are any, it will neither impose direct compliance costs on federally recognized Tribal governments nor preempt Tribal law. Thus, Executive Order 13175 does not apply to this final rule.

Consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA offered government-to-government consultation with Tribes in April 2024. The offer of direct consultation was declined.

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

Executive Order 13045 directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in Federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is not subject to Executive Order 13045 because it is not a significant regulatory action under section 3(f)(1) of Executive Order 12866.

However, the EPA's *Policy on Children's Health* applies to this action. This action is consistent with the EPA's *Policy on Children's Health* because the new technology-based standards provide a maximum level of emission control that is implementable for all stationary combustion turbines. As described in the proposal, the EPA also considered more stringent $NO_X$ standards for most subcategories of new, modified, or reconstructed units based on an expanded application post-combustion control technology, but determined that this technology (specifically, SCR) is not the BSER other than for new large high-utilization combustion turbines.

*I. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use*

This action is not a "significant energy action" because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. This action includes defining and setting emission limits for affected new, modified, and reconstructed sources; applicability-related and definitional changes; changes to the startup, shutdown, and malfunction (SSM) provisions; and the testing, monitoring, recordkeeping, and reporting requirements. This does not impact energy supply, distribution, or use and the EPA does not expect a significant change in retail electricity prices or availability on average across the contiguous U.S. for natural gas-fired generation, or significant impacts on utility power sector delivered natural gas prices.

*J. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51*

This action involves technical standards. As discussed in the proposal preamble,[211] the EPA conducted searches for the Review of New Source Performance Standards for Stationary Combustion Turbines through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards

[211] 89 FR 101306 (Dec. 13, 2024).

Institute (ANSI). Searches were conducted for EPA Methods 1, 2, 3A, 6, 6C, 7E, 8, 19, and 20 of 40 CFR part 60, appendix A. No applicable voluntary consensus standards (VCS) were identified for EPA Methods 1, 2, 3A, 6, 6C, 7E, 8, 19, and 20. All potential standards were reviewed to determine the practicality of the VCS for this rulemaking. One VCS was identified as an acceptable alternative to EPA test methods for the purpose of this final rule: [212]

• American Society for Testing and Materials (ASTM) D6348–12 (R2020), ''Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform (FTIR) Spectroscopy,'' is an acceptable alternative to EPA Method 320, with the conditions discussed below.

When using ASTM D6348–12 (R2020), the following conditions must be met:

(1) The test plan preparation and implementation in the Annexes to ASTM D 6348–12 (R2020), Sections A1 through A8 are mandatory; and

(2) In ASTM D6348–12 (R2020) Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (Equation A5.5). For the test data to be acceptable for a compound, %R must be 70% $\geq$ R $\leq$ 130%. If the %R value does not meet this criterion for a target compound, the test data is not acceptable for that compound and the test must be repeated for that analyte (*i.e.,* the sampling and/or analytical procedure should be adjusted before a retest). The %R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated %R value for that compound by using the following equation:

*Reported Results = ((Measured Concentration in Stack))/(%R)* $\times$ *100*

The search identified 13 VCS that were potentially applicable for this final rule in lieu of EPA reference methods. However, these have been determined to not be practical due to lack of equivalency, documentation, validation of data, and other important technical and policy considerations. Additional information for the VCS search and determinations can be found in the memorandum titled, *Voluntary Consensus Standard Search Results for New Source Performance Standards Review for Stationary Combustion Turbines and Stationary Gas Turbines (40 CFR part 60, subpart KKKKa).*

In addition, final rule updates to 40 CFR 60.17 (incorporations by reference) are to include additional test methods identified in subpart KKKKa. The Agency does not intend for these editorial revisions to substantively change any of the technical requirements of existing subparts GG and KKKK. These test methods are: ASTM D129–00; ASTM D240–19; ASTM D396–98; ASTM D975–08a; ASTM D1072–90 (Reapproved 1999); ASTM D1266–98 (Reapproved 2003); ASTM D1552–03; ASTM D1826–94 (Reapproved 2003); ASTM D2622–05; ASTM D3246–05; ASTM D3588–98 (Reapproved 2003); ASTM D3699–08; ASTM D4057–95 (Reapproved 2000); ASTM D4084–05; ASTM D4177–95 (Reapproved 2000); ASTM D4294–03; ASTM D4468–85 (Reapproved 2000); ASTM D4809–18; ASTM D4810–88 (Reapproved 1999); ASTM D4891–89 (Reapproved 2006); ASTM D5287–97 (Reapproved 2002); ASTM D5453–05; ASTM D5504–20; ASTM D5623–24; ASTM D6228–98 (Reapproved 2003); ASTM D6348–12 (Reapproved 2020); ASTM D6522–20; ASTM D6667–04; ASTM D6751–11b; ASTM D7039–24; ASTM D7467–10; GPA 2140–17; GPA 2166–17; GPA 2172–09; GPA 2174–14; and GPA 2377–86.

The EPA is also finalizing the option for facilities to use 40 CFR part 63, Appendix A, EPA Method 320 for $NO_X$ testing of sources subject to either subparts GG, KKKK, or KKKKa.[213] This will also provide testing flexibility and increase efficiency for test firms concurrently performing formaldehyde testing on KKKK and KKKKa sources subject to the stationary combustion turbine NESHAP requirements under 40 CFR part 63, subpart YYYY. Similarly, the EPA allows the option to use ASTM Method D6348–12 (2020) as an equivalent FTIR alternative to Method 320 provided the conditions specified above are met.

In accordance with the requirements of 1 CFR part 51, the EPA is incorporating the following four voluntary consensus standards by reference in the final rule.

• ASTM D5504–20, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, covers the determination of sulfur-containing compounds in high methane content gaseous fuels such as natural gas. It can be used to determine the sulfur content of gaseous fuels in the rule.

• ASTM D5623–24, Standard Test Method for Sulfur Compounds in Light Petroleum Liquids by Gas Chromatography and Sulfur Selective Detection, covers the determination of volatile sulfur-containing compounds in light petroleum liquids. It can be used to determine the sulfur content of liquid fuels in the rule.

• ASTM D6348–12, Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform (FTIR) Spectroscopy. It can be used as an equivalent FTIR alternative to Method 320 provided the conditions specified above are met.

• ASTM D7039–24, Standard Test Method of Sulfur in Gasoline, Diesel Fuel, Jet Fuel, Kerosine, Biodiesel, Biodiesel Blends, and Gasoline-Ethanol Blends by Monochromatic Wavelengths Dispersive X-ray Fluorescence Spectrometry, covers the determination of total sulfur by monochromatic wavelength-dispersive X-ray fluorescence spectrometry in various fuels. It can be used to determine the sulfur content of liquid fuels in the rule.

The EPA determined that the ASTM standards are reasonably available because they are available for purchase or access from the following addresses: ASTM International, 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959, +1.610.832.9500, *www.astm.org.*

*K. Congressional Review Act (CRA)*

This action is subject to the Congressional Review Act (CRA), and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

**List of Subjects in 40 CFR Part 60**

Environmental protection, Administrative practice and procedures, Air pollution control, Incorporation by reference, Reporting and recordkeeping requirements.

**Lee Zeldin,**

*Administrator.*

For the reasons set forth in the preamble, the Environmental Protection Agency amends part 60 of title 40, chapter I, of the Code of Federal Regulations as follows:

[212] ANSI/ASME PTC 19.10–1981 Part 10 (2010) has been removed as a VCS alternative due to withdrawn or outdated testing methodologies.

[213] EPA Method 320 can also be used to determine moisture ($H_2O$) content, when necessary. However, EPA Method 320 cannot be used to determine the $O_2$ content of the flue gas stream. The oxygen content must be determined via a method prescribed by the NSPS, which in turn is used to correct the $NO_X$ ppm concentration to 15 percent $O_2$, where applicable.

## PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

## Subpart A—General Provisions

■ 2. Amend § 60.17 by revising paragraphs (h) and (m)(1) through (4) and (6) to read as follows:

### § 60.17 Incorporations by reference.

* * * * *

(h) ASTM International, 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–2959; phone: (800) 262–1373; website: *www.astm.org.*

(1) ASTM A99–76, Standard Specification for Ferromanganese; IBR approved for § 60.261.

(2) ASTM A99–82 (Reapproved 1987), Standard Specification for Ferromanganese; IBR approved for § 60.261.

(3) ASTM A100–69, Standard Specification for Ferrosilicon; IBR approved for § 60.261.

(4) ASTM A100–74, Standard Specification for Ferrosilicon; IBR approved for § 60.261.

(5) ASTM A100–93, Standard Specification for Ferrosilicon; IBR approved for § 60.261.

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

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

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

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

(10) ASTM A483–64, Standard Specification for Silicomanganese; IBR approved for § 60.261.

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

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

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

(14) ASTM D86–78, Distillation of Petroleum Products; IBR approved for §§ 60.562–2(d); 60.593(d); 60.593a(d); 60.633(h).

(15) ASTM D86–82, Distillation of Petroleum Products; IBR approved for §§ 60.562–2(d); 60.593(d); 60.593a(d); 60.633(h).

(16) ASTM D86–90, Distillation of Petroleum Products; IBR approved for §§ 60.562–2(d); 60.593(d); 60.593a(d); 60.633(h).

(17) ASTM D86–93, Distillation of Petroleum Products; IBR approved for § 60.593a(d).

(18) ASTM D86–95, Distillation of Petroleum Products; IBR approved for §§ 60.562–2(d); 60.593(d); 60.593a(d); 60.633(h).

(19) ASTM D86–96, Distillation of Petroleum Products, approved April 10, 1996; IBR approved for §§ 60.562–2(d); 60.593(d); 60.593a(d); 60.633(h); 60.5401(f); 60.5401a(f); 60.5402b(d); 60.5402c(d).

(20) ASTM D129–64, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method); IBR approved for § 60.106(j) and appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(21) ASTM D129–78, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method); IBR approved for § 60.106(j) and appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(22) ASTM D129–95, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method); IBR approved for § 60.106(j) and appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(23) ASTM D129–00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method); IBR approved for § 60.335(b).

(24) ASTM D129–00 (Reapproved 2005), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method); IBR Approved for §§ 60.4360a(c) and 60.4415(a).

(25) ASTM D240–76, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter; IBR approved for §§ 60.46(c); 60.296(b); and appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(26) ASTM D240–92, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter; IBR approved for §§ 60.46(c); 60.296(b); and appendix A–7: Method 19, Section 12.5.2.2.3.

(27) ASTM D240–02 (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, approved May 1, 2007; IBR approved for § 60.107a(d).

(28) ASTM D240–19, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, approved November 1, 2019; IBR approved for §§ 60.485b(g) and 60.4360a(c).

(29) ASTM D270–65, Standard Method of Sampling Petroleum and Petroleum Products; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.2.1.

(30) ASTM D270–75, Standard Method of Sampling Petroleum and Petroleum Products; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.2.1.

(31) ASTM D323–82, Test Method for Vapor Pressure of Petroleum Products (Reid Method); IBR approved for §§ 60.111(l); 60.111a(g); 60.111b; 60.116b(f).

(32) ASTM D323–94, Test Method for Vapor Pressure of Petroleum Products (Reid Method); IBR approved for §§ 60.111(l); 60.111a(g); 60.111b; 60.116b(f).

(33) ASTM D388–77, Standard Specification for Classification of Coals by Rank; IBR approved for §§ 60.41; 60.45(f); 60.41Da; 60.41b; 60.41c; 60.251.

(34) ASTM D388–90, Standard Specification for Classification of Coals by Rank; IBR approved for §§ 60.41; 60.45(f); 60.41Da; 60.41b; 60.41c; 60.251.

(35) ASTM D388–91, Standard Specification for Classification of Coals by Rank; IBR approved for §§ 60.41; 60.45(f); 60.41Da; 60.41b; 60.41c; 60.251.

(36) ASTM D388–95, Standard Specification for Classification of Coals by Rank; IBR approved for §§ 60.41; 60.45(f); 60.41Da; 60.41b; 60.41c; 60.251.

(37) ASTM D388–98a, Standard Specification for Classification of Coals by Rank; IBR approved for §§ 60.41; 60.45(f); 60.41Da; 60.41b; 60.41c; 60.251.

(38) ASTM D388–99 (Reapproved 2004)$^{\varepsilon 1}$(ASTM D388–99R04), Standard Classification of Coals by Rank, approved June 1, 2004; IBR approved for §§ 60.41; 60.45(f); 60.41Da; 60.41b; 60.41c; 60.251; 60.5580; 60.5580a.

(39) ASTM D396–78, Standard Specification for Fuel Oils; IBR approved for §§ 60.41b; 60.41c; 60.111(b); 60.111a(b).

(40) ASTM D396–89, Standard Specification for Fuel Oils; IBR approved for §§ 60.41b; 60.41c; 60.111(b); 60.111a(b).

(41) ASTM D396–90, Standard Specification for Fuel Oils; IBR approved for §§ 60.41b; 60.41c; 60.111(b); 60.111a(b).

(42) ASTM D396–92, Standard Specification for Fuel Oils; IBR approved for §§ 60.41b; 60.41c; 60.111(b); 60.111a(b).

(43) ASTM D396–98, Standard Specification for Fuel Oils, approved April 10, 1998; IBR approved for §§ 60.41b; 60.41c; 60.111(b); 60.111a(b); 60.4420a; 60.5580; 60.5580a.

(44) ASTM D975–78, Standard Specification for Diesel Fuel Oils; IBR approved for §§ 60.111(b) and 60.111a(b).

(45) ASTM D975–96, Standard Specification for Diesel Fuel Oils; IBR approved for §§ 60.111(b) and 60.111a(b).

(46) ASTM D975–98a, Standard Specification for Diesel Fuel Oils; IBR approved for §§ 60.111(b) and 60.111a(b).

(47) ASTM D975–08a, Standard Specification for Diesel Fuel Oils, approved October 1, 2008; IBR approved for §§ 60.41b; 60.41c; 60.4420a; 60.5580; 60.5580a.

(48) ASTM D1072–80, Standard Test Method for Total Sulfur in Fuel Gases; IBR approved for § 60.335(b).

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

(50) ASTM D1072–90 (Reapproved 1999), Standard Test Method for Total Sulfur in Fuel Gases; IBR approved for §§ 60.4360a(c) and 60.4415(a).

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

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

(53) ASTM D1193–77, Standard Specification for Reagent Water; IBR approved for appendix A–3 to part 60: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; appendix A–4 to part 60: Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; appendix A–5 to part 60: Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; appendix A–8 to part 60: Method 26, Section 7.1.2; Method 26A, Section 7.1.2; Method 29, Section 7.2.2.

(54) ASTM D1193–91, Standard Specification for Reagent Water; IBR approved for appendix A–3 to part 60: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; appendix A–4 to part 60: Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; appendix A–5 to part 60: Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; appendix A–8 to part 60: Method 26, Section 7.1.2; Method 26A, Section 7.1.2; Method 29, Section 7.2.2.

(55) ASTM D1266–87, Standard Test Method for Sulfur in Petroleum Products (Lamp Method); IBR approved for § 60.106(j).

(56) ASTM D1266–91, Standard Test Method for Sulfur in Petroleum Products (Lamp Method); IBR approved for § 60.106(j).

(57) ASTM D1266–98, Standard Test Method for Sulfur in Petroleum Products (Lamp Method); IBR approved for §§ 60.106(j) and 60.335(b).

(58) ASTM D1266–98 (Reapproved 2003)$^{\varepsilon,1}$ Standard Test Method for Sulfur in Petroleum Products (Lamp Method); IBR approved for §§ 60.4360a(c) and 60.4415(a).

(59) ASTM D1475–60 (Reapproved 1980), Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products; IBR approved for § 60.435(d), appendix A–7 to part 60: Method 24, Sections 6.1 and 11.3.3; Method 24A, Sections 6.5,7.1, 11.2, 11.3, and 16.0.

(60) ASTM D1475–90, Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products; IBR approved for § 60.435(d); appendix A–7 to part 60: Method 24, Sections 6.1 and 11.3.3; Method 24A, Sections 6.5, 7.1, 11.2, 11.3, and 16.0.

(61) ASTM D1475–13, Standard Test Method for Density of Liquid Coatings, Inks, and Related Products, approved November 1, 2013; IBR approved for § 60.393a(f).

(62) ASTM D1552–83, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method); IBR approved for § 60.106(j) and appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(63) ASTM D1552–95, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method); IBR approved for § 60.106(j) and appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(64) ASTM D1552–01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method; IBR approved for § 60.335(b).

(65) ASTM D1552–03, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method); IBR approved for §§ 60.4360a(c) and 60.4415(a).

(66) ASTM D1826–77, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter; IBR approved for §§ 60.45(f); 60.46(c); 60.296(b); appendix A–7 to part 60: Method 19, Section 12.3.2.4.

(67) ASTM D1826–94, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter; IBR approved for §§ 60.45(f); 60.46(c); 60.296(b); appendix A–7 to part 60: Method 19, Section 12.3.2.4.

(68) ASTM D1826–94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, approved May 10, 2003; IBR approved for §§ 60.107a(d) and 60.4360a(c).

(69) ASTM D1835–87, Standard Specification for Liquefied Petroleum (LP) Gases; IBR approved for §§ 60.41b; 60.41c.

(70) ASTM D1835–91, Standard Specification for Liquefied Petroleum (LP) Gases; IBR approved for §§ 60.41Da; 60.41b; 60.41c.

(71) ASTM D1835–97, Standard Specification for Liquefied Petroleum (LP) Gases; IBR approved for §§ 60.41Da; 60.41b; 60.41c.

(72) ASTM D1835–03a, Standard Specification for Liquefied Petroleum (LP) Gases; IBR approved for §§ 60.41Da; 60.41b; 60.41c; 60.4420a.

(73) ASTM D1945–64, Standard Method for Analysis of Natural Gas by Gas Chromatography; IBR approved for § 60.45(f).

(74) ASTM D1945–76, Standard Method for Analysis of Natural Gas by Gas Chromatography; IBR approved for § 60.45(f).

(75) ASTM D1945–91, Standard Method for Analysis of Natural Gas by Gas Chromatography; IBR approved for § 60.45(f).

(76) ASTM D1945–96, Standard Method for Analysis of Natural Gas by Gas Chromatography; IBR approved for § 60.45(f).

(77) ASTM D1945–03 (Reapproved 2010), Standard Method for Analysis of Natural Gas by Gas Chromatography, approved January 1, 2010; IBR approved for §§ 60.107a(d); 60.5413(d); 60.5413a(d); 60.5413b(d); 60.5413c(d).

(78) ASTM D1945–14 (Reapproved 2019), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, approved December 1, 2019; IBR approved for § 60.485b(g).

(79) ASTM D1946–77, Standard Method for Analysis of Reformed Gas by Gas Chromatography; IBR approved for §§ 60.18(f); 60.45(f); 60.564(f); 60.614(e); 60.664(e); 60.704(d).

(80) ASTM D1946–90 (Reapproved 1994), Standard Method for Analysis of Reformed Gas by Gas Chromatography; IBR approved for §§ 60.18(f); 60.45(f); 60.564(f); 60.614(e); 60.664(e); 60.704(d).

(81) ASTM D1946–90 (Reapproved 2006), Standard Method for Analysis of Reformed Gas by Gas Chromatography, approved June 1, 2006; IBR approved for § 60.107a(d).

(82) ASTM D2013–72, Standard Method of Preparing Coal Samples for Analysis; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(83) ASTM D2013–86, Standard Method of Preparing Coal Samples for Analysis; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(84) ASTM D2015–77 (Reapproved 1978), Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter; IBR approved for §§ 60.45(f); 60.46(c); and appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(85) ASTM D2015–96, Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter; IBR approved for §§ 60.45(f); 60.46(c); and appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(86) ASTM D2016–74, Standard Test Methods for Moisture Content of Wood; IBR approved for appendix A–8 to part 60: Method 28, Section 16.1.1.

(87) ASTM D2016–83, Standard Test Methods for Moisture Content of Wood; IBR approved for appendix A–8 to part 60: Method 28, Section 16.1.1.

(88) ASTM D2234–76, Standard Methods for Collection of a Gross Sample of Coal; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.1.

(89) ASTM D2234–96, Standard Methods for Collection of a Gross Sample of Coal; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.1.

(90) ASTM D2234–97a, Standard Methods for Collection of a Gross Sample of Coal; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.1.

(91) ASTM D2234–98, Standard Methods for Collection of a Gross Sample of Coal; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.1.

(92) ASTM D2369–81, Standard Test Method for Volatile Content of Coatings; IBR approved for appendix A–7 to part 60: Method 24, Section 6.2.

(93) ASTM D2369–87, Standard Test Method for Volatile Content of Coatings; IBR approved for appendix A–7 to part 60: Method 24, Section 6.2.

(94) ASTM D2369–90, Standard Test Method for Volatile Content of Coatings; IBR approved for appendix A–7 to part 60: Method 24, Section 6.2.

(95) ASTM D2369–92, Standard Test Method for Volatile Content of Coatings; IBR approved for appendix A–7 to part 60: Method 24, Section 6.2.

(96) ASTM D2369–93, Standard Test Method for Volatile Content of Coatings; IBR approved for appendix A–7 to part 60: Method 24, Section 6.2.

(97) ASTM D2369–95, Standard Test Method for Volatile Content of Coatings; IBR approved for appendix A–7 to part 60: Method 24, Section 6.2.

(98) ASTM D2369–10 (Reapproved 2015)e1, Standard Test Method for Volatile Content of Coatings, approved June 1, 2015; IBR approved for appendix A–7 to part 60: Method 24, Section 6.2.

(99) ASTM D2369–20, Standard Test Method for Volatile Content of Coatings, approved June 1, 2020; IBR approved for §§ 60.393a(f); 60.723(b); 60.724(a); 60.725(b); 60.723a(b); 60.724a(a); 60.725a(b).

(100) ASTM D2382–76, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method); IBR approved for §§ 60.18(f); 60.485(g); 60.485a(g); 60.564(f); 60.664(e); 60.704(d).

(101) ASTM D2382–88, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method); IBR approved for §§ 60.18(f); 60.485(g); 60.485a(g); 60.564(f); 60.704(d).

(102) ASTM D2504–67, Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography; IBR approved for §§ 60.485(g) and 60.485a(g).

(103) ASTM D2504–77, Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography; IBR approved for §§ 60.485(g) and 60.485a(g).

(104) ASTM D2504–88 (Reapproved 1993), Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography; IBR approved for §§ 60.485(g) and 60.485a(g).

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

(106) ASTM D2584–94, Standard Test Method for Ignition Loss of Cured Reinforced Resins; IBR approved for § 60.685(c).

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

(108) ASTM D2622–87, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry; IBR approved for § 60.106(j).

(109) ASTM D2622–94, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry; IBR approved for § 60.106(j).

(110) ASTM D2622–98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry; IBR approved for §§ 60.106(j) and 60.335(b).

(111) ASTM D2622–05, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry; IBR approved for §§ 60.4360a(c) and 60.4415(a).

(112) ASTM D2697–22, Standard Test Method for Volume Nonvolatile Matter in Clear or Pigmented Coatings, approved July 1, 2022; IBR approved for §§ 60.393a(g); 60.723(b); 60.724(a); 60.725(b); 60.723a(b); 60.724a(a); 60.725a(b).

(113) ASTM D2879–83, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, approved 1983; IBR approved for §§ 60.111b; 60.116b(e) and (f); 60.485(e); 60.485a(e); 60.5403b(d); 60.5406c(d).

(114) ASTM D2879–96, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, approved 1996; IBR approved for §§ 60.111b; 60.116b(e) and (f); 60.485(e); 60.485a(e); 60.5403b(d); 60.5406c(d).

(115) ASTM D2879–97, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, approved 1997; IBR approved for §§ 60.111b; 60.116b(e) and (f); 60.485(e); 60.485a(e); 60.5403b(d); 60.5406c(d).

(116) ASTM D2879–23, Standard Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, approved December 1, 2019; IBR approved for § 60.485b(e).

(117) ASTM D2880–78, Standard Specification for Gas Turbine Fuel Oils; IBR approved for §§ 60.111(b) and 60.111a(b).

(118) ASTM D2880–96, Standard Specification for Gas Turbine Fuel Oils; IBR Approved for §§ 60.111(b) and 60.111a(b).

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

(120) ASTM D2908–91, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection

Gas Chromatography; IBR approved for § 60.564(j).

(121) ASTM D2986–71, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test; IBR approved for appendix A–3 to part 60: Method 5, Section 7.1.1; appendix A–5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(122) ASTM D2986–78, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test; IBR approved for appendix A–3 to part 60: Method 5, Section 7.1.1; appendix A–5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(123) ASTM D2986–95a, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test; IBR approved for appendix A–3 to part 60: Method 5, Section 7.1.1; appendix A–5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(124) ASTM D3173–73, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(125) ASTM D3173–87, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(126) ASTM D3176–74, Standard Method for Ultimate Analysis of Coal and Coke; IBR approved for § 60.45(f) and appendix A–7 to part 60: Method 19, Section 12.3.2.3.

(127) ASTM D3176–89, Standard Method for Ultimate Analysis of Coal and Coke; IBR approved for § 60.45(f) and appendix A–7 to part 60: Method 19, Section 12.3.2.3.

(128) ASTM D3177–75, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(129) ASTM D3177–89, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

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

(131) ASTM D3178–89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke; IBR approved for § 60.45(f).

(132) ASTM D3246–81, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry; IBR approved for § 60.335(b).

(133) ASTM D3246–92, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry; IBR approved for § 60.335(b).

(134) ASTM D3246–96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry; IBR approved for § 60.335(b).

(135) ASTM D3246–05, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry; IBR approved for §§ 60.4360a(c) and 60.4415(a).

(136) ASTM D3270–73T, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method); IBR approved for appendix A–5 to part 60: Method 13A, Section 16.1.

(137) ASTM D3270–80, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method); IBR approved for appendix A–5 to part 60: Method 13A, Section 16.1.

(138) ASTM D3270–91, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method); IBR approved for appendix A–5 to part 60: Method 13A, Section 16.1.

(139) ASTM D3270–95, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method); IBR approved for appendix A–5 to part 60: Method 13A, Section 16.1.

(140) ASTM D3286–85, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(141) ASTM D3286–96, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(142) ASTM D3370–76, Standard Practices for Sampling Water; IBR approved for § 60.564(j).

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

(144) ASTM D3588–98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, approved May 10, 2003; IBR approved for §§ 60.107a(d); 60.4360a(c); 60.5413(d); 60.5413a(d); 60.5413b(d); 60.5413c(d).

(145) ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, approved September 1, 2008; IBR approved for §§ 60.41b; 60.41c; 60.4420a; 60.5580; 60.5580a.

(146) ASTM D3792–79, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph; IBR approved for appendix A–7 to part 60: Method 24, Section 6.3.

(147) ASTM D3792–91, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph; IBR approved for appendix A–7 to part 60: Method 24, Section 6.3.

(148) ASTM D4017–81, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method; IBR approved for appendix A–7 to part 60: Method 24, Section 6.4.

(149) ASTM D4017–90, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method; IBR approved for appendix A–7 to part 60: Method 24, Section 6.4.

(150) ASTM D4017–96a, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method; IBR approved for appendix A–7 to part 60: Method 24, Section 6.4.

(151) ASTM D4057–81, Standard Practice for Manual Sampling of Petroleum and Petroleum Products; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(152) ASTM D4057–95, Standard Practice for Manual Sampling of Petroleum and Petroleum Products; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.2.3.

(153) ASTM D4057–95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products; IBR approved for §§ 60.4360a(b) and 60.4415(a).

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

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

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

(157) ASTM D4177–95, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.2.1.

(158) ASTM D4177–95 (Reapproved 2000), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products; IBR approved for §§ 60.4360a(b) and 60.4415(a).

(159) ASTM D4239–85, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(160) ASTM D4239–94, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(161) ASTM D4239–97, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods; IBR approved for appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

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

(163) ASTM D4294–03, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry; IBR approved for §§ 60.4360a(c) and 60.4415(a).

(164) ASTM D4442–84, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials; IBR approved for appendix A–8 to part 60: Method 28, Section 16.1.1.

(165) ASTM D4442–92, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials; IBR approved for appendix A–8 to part 60: Method 28, Section 16.1.1.

(166) ASTM D4444–92, Standard Test Methods for Use and Calibration of Hand-Held Moisture Meters; IBR approved for appendix A–8 to part 60: Method 28, Section 16.1.1.

(167) ASTM D4457–85 (Reapproved 1991), Test Method for Determination of Dichloromethane and 1,1,1-Trichloroethane in Paints and Coatings by Direct Injection into a Gas Chromatograph; IBR approved for appendix A–7 to part 60: Method 24, Section 6.5.

(168) ASTM D4468–85 (Reapproved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry; IBR approved for §§ 60.335(b); 60.4360a(c); 60.4415(a).

(169) ASTM D4468–85 (Reapproved 2006), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, approved June 1, 2006; IBR approved for § 60.107a(e).

(170) ASTM D4629–02, Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection; IBR approved for §§ 60.49b(e) and 60.335(b).

(171) ASTM D4809–95, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method); IBR approved for §§ 60.18(f); 60.485(g); 60.485a(g); 60.564(f); 60.704(d).

(172) ASTM D4809–06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), approved December 1, 2006; IBR approved for § 60.107a(d).

(173) ASTM D4809–18, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), approved July 1, 2018; IBR approved for §§ 60.485b(g) and 60.4360a(c).

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

(175) ASTM D4840–99(2018)e1, Standard Guide for Sample Chain-of-Custody Procedures, approved August 2018; IBR approved for Appendix A–7: Method 23, Section 8.2.12.

(176) ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, approved June 1, 2006; IBR approved for §§ 60.107a(d); 60.4360a(c); 60.5413(d); 60.5413a(d); 60.5413b(d); 60.5413c(d).

(177) ASTM D5066–91 (Reapproved 2017), Standard Test Method for Determination of the Transfer Efficiency Under Production Conditions for Spray Application of Automotive Paints—Weight Basis, approved June 1, 2017; IBR approved for § 60.393a(h).

(178) ASTM D5087–02 (Reapproved 2021), Standard Test Method for Determining Amount of Volatile Organic Compound (VOC) Released from Solventborne Automotive Coatings and Available for Removal in a VOC Control Device (Abatement), approved February 1, 2021; IBR approved for § 60.397a(e) and appendix A to subpart MMa.

(179) ASTM D5287–97 (Reapproved 2002), Standard Practice for Automatic Sampling of Gaseous Fuels; IBR approved for §§ 60.4360a(b) and 60.4415(a).

(180) ASTM D5403–93, Standard Test Methods for Volatile Content of Radiation Curable Materials; IBR approved for appendix A–7 to part 60: Method 24, Section 6.6.

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

(182) ASTM D5453–05, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence; IBR approved for §§ 60.4360a(c) and 60.4415(a).

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

(184) ASTM D5504–08, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, approved June 15, 2008; IBR approved for § 60.107a(e).

(185) ASTM D5504–20, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, approved November 1, 2020; IBR approved for § 60.4360a(c).

(186) ASTM D5623–19, Standard Test Method for Sulfur Compounds in Light Petroleum Liquids by Gas Chromatography and Sulfur Selective Detection, approved July 1, 2019; IBR approved for § 60.4415(a).

(187) ASTM D5623–24, Standard Test Method for Sulfur Compounds in Light Petroleum Liquids by Gas Chromatography and Sulfur Selective Detection, approved March 1, 2024; IBR approved for § 60.4360a(c).

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

(189) ASTM D5865–98, Standard Test Method for Gross Calorific Value of Coal and Coke; IBR approved for §§ 60.45(f); 60.46(c); and appendix A–7 to part 60: Method 19, Section 12.5.2.1.3.

(190) ASTM D5865–10, Standard Test Method for Gross Calorific Value of Coal and Coke, approved January 1, 2010; IBR approved for §§ 60.45(f); 60.46(c); and appendix A–7 to part 60: Method 19, section 12.5.2.1.3.

(191) ASTM D5965–02 (Reapproved 2013), Standard Test Methods for Specific Gravity of Coating Powders, approved June 1, 2013; IBR approved for § 60.393a(f).

(192) ASTM D6093–97 (Reapproved 2016), Standard Test Method for Percent Volume Nonvolatile Matter in Clear or

Pigmented Coatings Using a Helium Gas Pycnometer, approved December 1, 2016; IBR approved for §§ 60.393a(g); 60.723(b); 60.724(a); 60.725(b); 60.723a(b); 60.724a(a); 60.725a(b).

(193) ASTM D6216–20, Standard Practice for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications, approved September 1, 2020; IBR approved for appendix B to part 60.

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

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

(196) ASTM D6266–00a (Reapproved 2017), Standard Test Method for Determining the Amount of Volatile Organic Compound (VOC) Released from Waterborne Automotive Coatings and Available for Removal in a VOC Control Device (Abatement), approved July 1, 2017; IBR approved for § 60.397a(e).

(197) ASTM D6348–03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, approved October 1, 2003; IBR approved for § 60.73a(b); table 7 to subpart IIII; table 2 to subpart JJJJ; § 60.4245(d).

(198) ASTM D6348–12e1, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, approved February 1, 2012; IBR approved for § 60.5413c(b).

(199) ASTM D6348–12 (Reapproved 2020), Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, approved December 1, 2020; IBR approved for §§ 60.4400(a) and 60.4400a(b).

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

(201) ASTM D6377–20, Standard Test Method for Determination of Vapor Pressure of Crude Oil: $VPCR_X$ (Expansion Method), approved June 1, 2020; IBR approved for § 60.113c(d).

(202) ASTM D6378–22, Standard Test Method for Determination of Vapor Pressure (VPX) of Petroleum Products, Hydrocarbons, and Hydrocarbon-Oxygenate Mixtures (Triple Expansion Method), approved July 1, 2022; IBR approved for § 60.113c(d).

(203) ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, approved October 1, 2004; IBR approved for § 60.107a(d).

(204) ASTM D6420–18, Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, approved November 1, 2018; IBR approved for §§ 60.485(g); 60.485a(g); 60.485b(g); 60.611a; 60.614(b) and (e); 60.614a(b) and (e), 60.664(b) and (e); 60.664a(b) and (f); 60.700(c); 60.704(b) (d), and (h); 60.705(l); 60.704a(b) and (f).

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

(206) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, approved October 1, 2005; IBR approved for table 2 to subpart JJJJ, §§ 60.5413(b); 60.5413a(b).

(207) ASTM D6522–11 Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, approved December 1, 2011; IBR approved for §§ 60.37f(a) and 60.766(a).

(208) ASTM D6522–20, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, approved June 1, 2020; IBR approved for §§ 60.4400(a); 60.4400a(b); 60.5413b(b); 60.5413c(b).

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

(210) ASTM D6667–04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence; IBR approved for §§ 60.4360a(c) and 60.4415(a).

(211) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, approved July 15, 2011; IBR approved for §§ 60.41b; 60.41c; 60.4420a; 60.5580; 60.5580a.

(212) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method); IBR approved for § 60.56c(b).

(213) ASTM D6784–02 (Reapproved 2008), Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved April 1, 2008; IBR approved for § 60.56c(b).

(214) ASTM D6784–16, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved March 1, 2016; IBR approved for appendix B to part 60.

(215) ASTM D6911–15 Standard Guide for Packaging and Shipping Environmental Samples for Laboratory Analysis, approved January 15, 2015; IBR approved for Appendix A–7: Method 23, Section 8.2.11; Appendix A–8: Method 30B, Section 8.3.3.8.

(216) ASTM D7039–15a, Standard Test Method for Sulfur in Gasoline, Diesel Fuel, Jet Fuel, Kerosine, Biodiesel, Biodiesel Blends, and Gasoline-Ethanol Blends by Monochromatic Wavelength Dispersive X-ray Fluorescence Spectrometry, approved July 1, 2015; IBR approved for § 60.4415(a).

(217) ASTM D7039–24, Standard Test Method for Sulfur in Gasoline, Diesel Fuel, Jet Fuel, Kerosine, Biodiesel, Biodiesel Blends, and Gasoline-Ethanol Blends by Monochromatic Wavelength Dispersive X-ray Fluorescence Spectrometry, approved December 1, 2024; IBR approved for § 60.4360a(c).

(218) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, approved August 1, 2010; IBR approved for §§ 60.41b; 60.41c; 60.4420a; 60.5580; 60.5580a.

(219) ASTM D7520–16, Standard Test Method for Determining the Opacity of a Plume in the Outdoor Ambient Atmosphere, approved April 1, 2016; IBR approved for §§ 60.123(c); 60.123a(c); 60.271(k); 60.272(a) and (b); 60.273(c) and (d); 60.274(i); 60.275(e); 60.276(c); 60.271a; 60.272a(a) and (b); 60.273a(c) and (d); 60.274a(h); 60.275a(e); 60.276a(f); 60.271b; 60.272b(a) and (b); 60.273b(c) and (d); 60.274b(h); 60.275b(e); 60.276b(f); 60.374a(d); 60.2972(a); tables 1, 1a, and 1b to subpart EEEE; § 60.3067(a); tables 2 and 2a to subpart FFFF.

(220) ASTM E168–67, General Techniques of Infrared Quantitative Analysis; IBR approved for §§ 60.485a(d); 60.593(b); 60.593a(b); 60.632(f).

(221) ASTM E168–77, General Techniques of Infrared Quantitative Analysis; IBR approved for §§ 60.485a(d); 60.593(b); 60.593a(b); 60.632(f).

(222) ASTM E168–92, General Techniques of Infrared Quantitative Analysis; IBR approved for §§ 60.485a(d); 60.593(b); 60.593a(b); 60.632(f); 60.5400; 60.5400a(f).

(223) ASTM E168–16 (Reapproved 2023), Standard Practices for General Techniques of Infrared Quantitative Analysis, approved January 1, 2023; IBR approved for §§ 60.485b(d); 60.5400b(a); 60.5400c(a); 60.5401c(a).

(224) ASTM E169–63, General Techniques of Ultraviolet Quantitative Analysis; IBR approved for §§ 60.485a(d); 60.593(b); 60.593a(b); 60.632(f).

(225) ASTM E169–77, General Techniques of Ultraviolet Quantitative Analysis; IBR approved for §§ 60.485a(d); 60.593(b); 60.593a(b); 60.632(f).

(226) ASTM E169–93, General Techniques of Ultraviolet Quantitative Analysis, approved May 15, 1993; IBR approved for §§ 60.485a(d); 60.593(b); 60.593a(b); 60.632(f); 60.5400(f); 60.5400a(f).

(227) ASTM E169–16 (Reapproved 2022), Standard Practices for General Techniques of Ultraviolet-Visible Quantitative Analysis, approved November 1, 2022; IBR approved for § 60.485b(d), 60.5400b(a); 60.5401b(a); 60.5400c(a); 60.5401c(a).

(228) ASTM E260–73, General Gas Chromatography Procedures; IBR approved for §§ 60.485a(d); 60.593(b); 60.593a(b); 60.632(f).

(229) ASTM E260–91, General Gas Chromatography Procedures; IBR approved for §§ 60.485a(d); 60.593(b); 60.593a(b); 60.632(f).

(230) ASTM E260–96, General Gas Chromatography Procedures, approved April 10, 1996; IBR approved for §§ 60.485a(d); 60.593(b); 60.593a(b); 60.632(f); 60.5400(f); 60.5400a(f); 60.5406(b); 60.5406a(b)(3); 60.5400b(a)(2); 60.5401b(a)(2); 60.5406b(b)(3); 60.5400c(a); 60.5401c(a).

(231) ASTM E260–96 (Reapproved 2019), Standard Practice for Packed Column Gas Chromatography, approved September 1, 2019; IBR approved for § 60.485b(d).

(232) ASTM E617–13, Standard Specification for Laboratory Weights and Precision Mass Standards, approved May 1, 2013; IBR approved for appendix A–3: Methods 4, 5, 5H, 5I, and appendix A–8: Method 29.

(233) ASTM E871–82 (Reapproved 2013), Standard Test Method for Moisture Analysis of Particulate Wood Fuels, approved August 15, 2013; IBR approved for appendix A–8: Method 28R.

(234) ASTM E1584–11, Standard Test Method for Assay of Nitric Acid, approved August 1, 2011; IBR approved for § 60.73a(c).

(235) ASTM E2515–11, Standard Test Method for Determination of Particulate Matter Emissions Collected by a Dilution Tunnel, approved November 1, 2011; IBR approved for §§ 60.534(c) and (d); 60.5476(f).

(236) ASTM E2618–13 Standard Test Method for Measurement of Particulate Matter Emissions and Heating Efficiency of Outdoor Solid Fuel-Fired Hydronic Heating Appliances, approved September 1, 2013; IBR approved for § 60.5476(g).

(237) ASTM E2779–10, Standard Test Method for Determining Particulate Matter Emissions from Pellet Heaters, approved October 1, 2010; IBR approved for § 60.534(a) and (f).

(238) ASTM E2780–10, Standard Test Method for Determining Particulate Matter Emissions from Wood Heaters, approved October 1, 2010; IBR approved for appendix A: Method 28R.

(239) ASTM UOP539–97, Refinery Gas Analysis by Gas Chromatography, (Copyright 1997); IBR approved for § 60.107a(d).

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(1) GPA Midstream Standard 2140–17 (GPA 2140–17), Liquified Petroleum Gas Specifications and Test Methods (Revised 2017); IBR approved for §§ 60.4360a(c) and 60.4415(a).

(2) GPA Midstream Standard 2166–17 (GPA 2166–17), Obtaining Natural Gas Samples for Analysis by Gas Chromatography, (Reaffirmed 2017); IBR approved for §§ 60.4360a(b) and 60.4415(a).

(3) GPA Standard 2172–09 (GPA 2172–09), Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (2009); IBR approved for §§ 60.107a(d) and 60.4360a(c).

(4) GPA Standard 2174–14 (GPA 2174–14), Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography, (Revised 2014); IBR approved for §§ 60.4360a(b) and 60.4415(a).

* * * * *

(6) GPA Standard 2377–86 (GPA 2377–84), Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, 1986 Revision; IBR approved for §§ 60.105(b); 60.107a(b); 60.334(h); 60.4360; 60.4360a(c); and 60.4415(a).

* * * * *

## Subpart GG—Standards of Performance for Stationary Gas Turbines

■ 3. Amend § 60.330 by revising paragraph (a) and adding paragraphs (c) through (e) to read as follows:

**§ 60.330 Applicability and designation of affected facility.**

(a) Except as provided for in paragraphs (c) through (e) of this section, the provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

* * * * *

(c) As an alternative to being subject to this subpart, the owner or operator of a stationary combustion turbine meeting the applicability of this subpart may petition the Administrator (in writing) to become subject to the requirements for modified units in subpart KKKKa of this part. If the Administrator grants the petition, the affected facility is no longer subject to this subpart and is subject to (unless the unit is modified or reconstructed in the future) the requirements for modified units in subpart KKKKa of this part. The Administrator can only grant the petition if it is determined that compliance with subpart KKKKa of this part would be equivalent to, or more stringent than, compliance with this subpart.

(d) Stationary gas turbines subject to subpart Da, KKKK, or KKKKa of this part are not subject to this subpart.

(e) A combustion turbine that is subject to this subpart and is not a ‘‘major source’’ or located at a ‘‘major source’’ (as that term is defined at 42

U.S.C. 7661 (2)) is exempt from the requirements of 42 U.S.C. 7661a(a).

■ 4. Amend § 60.331 by:

■ a. Revising paragraphs (a) and (g);

■ b. Removing and reserving paragraphs (m) and (n); and

■ c. Revising paragraphs (p) and (u).

The revisions read as follows:

**§ 60.331 Definitions.**

* * * * *

(a) *Stationary gas turbine* means any simple cycle gas turbine, regenerative cycle gas turbine, or any gas turbine portion of a combined cycle steam/electric generating system that is not self-propelled. It may, however, be mounted on a vehicle for portability. Portable combustion turbines are excluded from the definition of ''stationary combustion turbine,'' and not regulated under this part, if the turbine meets the definition of ''nonroad engine'' under title II of the Clean Air Act and applicable regulations and is certified to meet emission standards promulgated pursuant to title II of the Clean Air Act, along with all related requirements.

* * * * *

(g) *ISO standard day conditions* means 288 degrees Kelvin (15 °C, 59 °F), 60 percent relative humidity, and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

* * * * *

(p) *Gas turbine model* means a group of gas turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature, and turbine inlet pressure.

* * * * *

(u) *Natural gas* means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane) that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 15.5 degrees Celsius total sulfur. Additionally, natural gas must be composed of at least 70 percent methane by volume and have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Unless refined to meet the definition of natural gas in this paragraph (u), natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

* * * * *

■ 5. Amend § 60.332 by revising paragraphs (f) through (h) to read as follows:

**§ 60.332 Standard for nitrogen oxides.**

* * * * *

(f) Stationary gas turbines using water or steam injection for control of $NO_X$ emissions are exempt from paragraph (a) of this section when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and firefighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) of this section on a case-by-case basis as determined by the Administrator.

* * * * *

■ 6. Amend § 60.333 by revising the introductory text and paragraph (a) and adding paragraph (c) to read as follows:

**§ 60.333 Standard for sulfur dioxide.**

Except as provided in paragraph (c) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, every owner or operator subject to the provisions of this subpart shall comply with one or the other of the following conditions in paragraphs (a) and (b) of this section:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis; or

* * * * *

(c) Stationary gas turbines subject to either subpart J or Ja of this part are not subject to the $SO_2$ standards in this subpart.

■ 7. Amend § 60.334 by revising paragraphs (b)(3)(iii), (h)(1), and (j)(3) and adding paragraph (k) to read as follows:

**§ 60.334 Monitoring of operations.**

* * * * *

(b) * * *

(3) * * *

(iii) If the owner or operator has installed a $NO_X$ CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at subpart D of part 75, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in § 60.7(c). For affected units that are also regulated under part 75, the $NO_X$ emission rate may be monitored using a $NO_X$ diluent CEMS that is installed and certified in accordance with appendix A to part 75 and the QA program in appendix E to part 75, or the low mass emissions methodology in § 75.19 of this chapter.

* * * * *

(h) * * *

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in § 60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4,000 ppmw), ASTM D4084–82, D4084–94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86 (all of which are incorporated by reference, see § 60.17), which measure the major sulfur compounds may be used; and

* * * * *

(j) * * *

(3) *Ice fog.* Each period during which an exemption provided in § 60.332(f) is in effect shall be reported in writing to the Administrator in the semiannual report described in paragraph (k)(3) of this section. For each period, the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported.

* * * * *

(k) The reporting requirements for this subpart shall be as follows:

(1) *Reporting frequency.* All reports required under § 60.7(c) must be electronically submitted via the Compliance and Emissions Data Reporting Interface (CEDRI) by the 30th day following the end of each 6-month period.

(2) *Electronic reporting.* Beginning on March 16, 2026, within 60 days after the date of completing each performance test or CEMS performance evaluation that includes a RATA, you must submit

the results following the procedures specified in paragraph (k)(4) of this section. You must submit the report in a file format generated using the EPA's Electronic Reporting Tool (ERT). Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) accompanied by the other information required by § 60.8(f)(2) in PDF format.

(3) *General reporting requirements.* You must submit to the Administrator semiannual reports of the following recorded information. Beginning on January 15, 2027, or once the report template for this subpart has been available on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (k)(4) of this section. The date report templates 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.

(4) *CEDRI and CBI.* If you are required to submit notifications or reports following the procedure specified in this paragraph (k)(4), you must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). 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 in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (k)(4)(i) and (ii) of this section. 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. 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. 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 earlier in this paragraph (k)(4).

(i) 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. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Combustion Turbine Sector Lead. 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.

(ii) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Office, Mail Drop: C404–02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. In addition to the OAQPS Document Control Officer, ERT files should also be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should also be sent to the attention of the Stationary Combustion Turbine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(5) *System outage.* 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 (k)(5)(i) through (vii) of this section.

(i) 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.

(ii) The outage must have occurred within the period of time beginning 5 business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) 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.

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

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

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

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

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

(vi) 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.

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

(6) *Force majeure.* 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 (k)(6)(i) through (v) of this section.

(i) 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).

(ii) 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.

(iii) You must provide to the Administrator:

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

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

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

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

(iv) 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.

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

(7) *Record availability.* 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.

■ 8. Amend § 60.335 by revising paragraphs (a)(3), (a)(5)(ii)(A) and (B), (b)(2), (b)(7)(i), (b)(9)(ii), and (b)(10)(ii) to read as follows:

**§ 60.335 Test methods and procedures.**

(a) * * *

(3) To determine $NO_X$ and diluent concentration:

(i) Either EPA Method 7E in appendix A–4 to this part or EPA Method 320 in appendix A to part 63 of this chapter; and

(ii) Either EPA Method 3 or 3A in appendix A to this part.

* * * * *

(5) * * *

(ii) * * *

(A) If each of the individual traverse point $NO_X$ concentrations, normalized to 15 percent $O_2$, is within ±10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized $NO_X$ concentration during the stratification test; or

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

* * * * *

(b) * * *

(2) The 3-run performance test required by § 60.8 must be performed within ±5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in § 60.331).

* * * * *

(7) * * *

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load while the source is combusting the fuel that is a normal primary fuel for that source.

* * * * *

(9) * * *

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

(10) * * *

(ii) For gaseous fuels, ASTM D1072–80, D1072–90 (Reapproved 1994); D3246–81, D3246–92, D3246–96; D4468–85 (Reapproved 2000); or D6667–01 (all of which are incorporated by reference, see § 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

* * * * *

## Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

■ 9. Revise § 60.4305 to read as follows:

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

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

(b) Stationary combustion turbines regulated under this subpart are not subject to subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are not subject to subparts Da, Db, and Dc of this part.

(c) Stationary combustion turbines subject to subpart KKKKa of this part are not subject to this subpart.

(d) As an alternative to being subject to this subpart, the owner or operator of an affected stationary combustion turbine meeting the applicability of this subpart may petition the Administrator (in writing) to become subject to the requirements for modified units in subpart KKKKa of this part. If the Administrator grants the petition, the affected facility is no longer subject to this subpart and is subject to (unless the unit is modified or reconstructed in the future) the requirements for modified units under subpart KKKKa of this part. The Administrator can only grant the petition if it is determined that compliance with subpart KKKKa of this part would be equivalent to, or more stringent than, compliance with this subpart.

(e) Stationary gas turbines subject to title II of the Clean Air Act are not subject to this subpart.

■ 10. Amend § 60.4310 by adding paragraphs (e) and (f) to read as follows:

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

* * * * *

(e) Military combustion turbines for use in other than a garrison facility and military combustion turbines installed for use as military training facilities are exempt from the $NO_X$ standards in this subpart.

(f) A combustion turbine that is subject to this subpart and is not a ''major source'' or located at a ''major source'' (as that term is defined at 42 U.S.C. 7661 (2)) is exempt from the requirements of 42 U.S.C. 7661a(a).

■ 11. Amend § 60.4320 by revising paragraph (a) and adding paragraph (c) to read as follows:

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

(a) Except as provided for in paragraph (c) of this section, you must meet the emission limits for $NO_X$ specified in table 1 to this subpart.

* * * * *

(c) A stationary combustion turbine that combusts byproduct fuels for which a facility-specific $NO_X$ emission standard has been established by the Administrator or delegated authority according to the requirements of paragraphs (c)(1) and (2) of this section is exempt from the emission limits specified in table 1 to this subpart.

(1) 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 byproduct fuel, is unable to comply with the applicable $NO_X$ emission standard determined using table 1 to this subpart.

(2) If the Administrator or delegated authority approves the request, a facility-specific $NO_X$ emissions standard will be established in a manner that the Administrator or delegated authority determines to be consistent with minimizing $NO_X$ emissions.

■ 12. Revise § 60.4325 to read as follows:

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

You must meet the emission limits specified in table 1 to this subpart. If your turbine operates below 75 percent of the peak load at any point during an operating hour, the part load standard is applicable during the entire operating hour. For non-part load operating hours, if your heat input is greater than or equal to 50 percent fuels other than natural gas at any point during an operating hour, you must meet the corresponding limit for fuels other than natural gas for that operating hour. For non-part load operating hours when your total heat input is greater than 50 percent natural gas for the entire operating hour while combusting some portion of non-natural gas fuels, you must meet the corresponding emissions standard as determined by prorating the applicable $NO_X$ standards, based on the applicable size category in table 1 to this subpart, by the heat input from each fuel type.

■ 13. Amend § 60.4330 by revising the section heading and paragraph (a)(3) and adding paragraph (c) to read as follows:

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

(a) * * *

(3) For each stationary combustion turbine burning 50 percent or more biogas and/or low-Btu gas on a calendar month basis, as determined based on total heat input, you must not cause to be discharged into the atmosphere from the affected source any gases that contain $SO_2$ in excess of:

(i) 650 milligrams of sulfur per standard cubic meter (mg/scm) (28 grains (gr) of sulfur per 100 standard cubic feet (scf)); or

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

* * * * *

(c) 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.

■ 14. Add § 60.4331 to read as follows:

**§ 60.4331 What are the requirements for operating a stationary temporary combustion turbine?**

(a) Notwithstanding any other provision of this subpart, you may operate a small- or medium-size stationary combustion turbine (*i.e.,* combustion turbine with a base load rating less than or equal to 850 MMBtu/h) at a single location for up to 24 consecutive months, so long as you comply with all of the requirements in paragraphs (b) through (e) of this section.

(b) You must meet the $NO_X$ emissions standard for stationary temporary combustion turbines in table 1 to this subpart and the applicable $SO_2$ emissions standard in § 60.4330.

(c) Unless you elect to demonstrate compliance through the otherwise-applicable monitoring, recordkeeping, and reporting requirements of this subpart, compliance with the $NO_X$ emissions standard must be demonstrated through maintaining the documentation in paragraphs (c)(1) and (2) of this section on-site:

(1) Each stationary temporary combustion turbine has a manufacturer's emissions guarantee at or below the full load $NO_X$ emissions standard in table 1 to this subpart; and

(2) Each such turbine has been performance tested at least once in the prior 5 years as meeting the $NO_X$ emissions standard in table 1 to this subpart.

(d) Unless you elect to demonstrate compliance through the otherwise-applicable monitoring, recordkeeping, and reporting requirements of this subpart, compliance with the $SO_2$ emissions standard must be demonstrated through complying with the provisions in § 60.4365.

(e) The conditions in paragraphs (e)(1) through (3) of this section apply in determining whether your stationary combustion turbine qualifies as a stationary temporary combustion turbine.

(1) The turbine may only be located at the same stationary source (or group of stationary sources located within a contiguous area and under common control) for a total period of 24 consecutive months. This is the total period of residence time allowed after the turbine commences operation at the location, regardless of whether the turbine is in operation for the entire 24-consecutive-month period.

(2) Any temporary combustion turbine that replaces a temporary combustion turbine at a stationary source and performs the same or similar function will be included in calculating the consecutive time period.

(3) The relocation of a stationary temporary combustion turbine within a single stationary source (or a group of stationary sources located within a contiguous area and under common control) while performing the same or similar function (*i.e.,* serving the same electric, mechanical, or thermal load) does not restart the 24-calendar-month residence time period.

■ 15. Amend § 60.4333 by revising paragraph (b) to read as follows:

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

* * * * *

(b) For multiple combustion turbines and with a common heat recovery unit, heat recovery units utilizing a common steam header, or using a common stack, the owner or operator shall either:

(1) Determine compliance with the applicable $NO_X$ emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit. The applicable emissions standard for the affected facility is equal to the prorated (by heat input) emissions standards of each of the individual combustion turbine engines that are exhausted through the single heat recovery steam generating unit;

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

(3) Monitor each combustion turbine separately by measuring the $NO_X$ emissions prior to mixing in the common stack.

■ 16. Amend § 60.4335 by adding paragraph (b)(5) to read as follows:

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

* * * * *

(b) * * *

(5) For affected units that are also regulated under part 75 of this chapter, the $NO_X$ emission rate may be monitored using a $NO_X$ diluent CEMS that is installed and certified in accordance with appendix A to part 75 and the QA program in appendix E to part 75, or the low mass emissions methodology in § 75.19 of this chapter.

■ 17. Amend § 60.4340 by revising paragraphs (a) and (b)(2)(iv) to read as follows:

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

(a) Except as provided for in paragraphs (a)(1) through (4) of this section, if you are not using water or steam injection to control $NO_X$ emissions, you must perform annual performance tests (no more than 14 calendar months following the previous performance test) in accordance with § 60.4400 to demonstrate continuous compliance.

(1) If the $NO_X$ emission result from the performance test is less than or equal to 75 percent of the $NO_X$ emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the $NO_X$ emission limit for the turbine, you must resume annual performance tests.

(2) 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 § 60.4375(d).

(3) If you own or operate an affected facility that has operated 168 operating hours or less in total or with a particular fuel since the date the previous performance test was required to be conducted, you may request an extension from the otherwise required performance test until after the affected facility has operated more than 168 operating hours in total or with a particular fuel since the date of the previous performance test was required to be conducted. A request for an extension under this paragraph (a)(3) 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 an extension is approved, a performance test must be conducted within 45 calendar days after the day the facility reaches 168 hours of operation since the date the previous performance test was required to be conducted. When the facility has operated more than 168 operating hours since the date the previous performance test was required to be conducted, the Administrator or delegated authority must be notified consistent with § 60.4375(d).

(4) 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 (a)(4)(i) through (v) of this section.

(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 facility at least once every 5 calendar years.

(b) * * *

(2) * * *

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

■ 18. Amend § 60.4345 by revising paragraphs (a), (c), and (e) to read as follows:

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

* * * * *

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

* * * * *

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

* * * * *

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

■ 19. Amend § 60.4350 by:

■ a. Removing and reserving paragraph (c); and

■ b. Revising paragraphs (d) and (f)(1).

The revisions read as follows:

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

* * * * *

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

* * * * *

(f) * * *

(1) For simple-cycle operation:

Equation 1 to Paragraph (f)(1)

$$E = \frac{(NO_X)_h \times (HI)_h}{P} \quad (Eq. 1)$$

Where:

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

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

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

P = gross energy output of the combustion turbine in MW. For an hour in which there is zero electrical load, you may calculate the pollutant emission rate using a default electrical load value equivalent to 5 percent of the maximum sustainable electrical load of the turbine.

* * * * *

■ 20. Amend § 60.4355 by revising paragraph (b) to read as follows:

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

* * * * *

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

■ 21. Revise § 60.4360 to read as follows:

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

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in § 60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in § 60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084–05, D4810–88 (Reapproved 1999), D5504–01, or D6228–98 (Reapproved 2003), 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.

■ 22. Amend § 60.4375 by revising paragraph (b) and adding paragraphs (c) through (j) to read as follows:

**§ 60.4375 What reports must I submit?**

* * * * *

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

(c) An owner or operator of an affected facility complying with § 60.4340(a)(2) must notify the Administrator or delegated authority within 15 calendar days after the facility recommences operation.

(d) An owner or operator of an affected facility complying with § 60.4340(a)(3) must notify the Administrator or delegated authority within 15 calendar days after the facility has operated more than 168 operating hours since the date the previous performance test was required to be conducted.

(e) Beginning on [March 16, 2026, within 60 days after the date of completing each performance test or continuous emissions monitoring systems (CEMS) performance evaluation that includes a RATA, you must submit the results following the procedures specified in paragraph (g) of this section. You must submit the report in a file format generated using the EPA's Electronic Reporting Tool (ERT). Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) accompanied by the other information required by § 60.8(f)(2) in PDF format.

(f) You must submit to the Administrator semiannual reports of the following recorded information. Beginning on January 15, 2027, or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (g) of this section. The date report templates 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.

(g) If you are required to submit notifications or reports following the procedure specified in this paragraph (g), you must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). 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 in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. 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. 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. 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 earlier in this paragraph (g).

(1) 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. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Combustion Turbine Sector Lead. 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.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Office, Mail Drop: C404–02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. In addition to the OAQPS Document Control Officer, ERT files should also be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should also be sent to the attention of the Stationary Combustion Turbine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(h) If you are required to electronically submit a report through CEDRI in 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 (h)(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 5 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.

(i) 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 (i)(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.

(j) 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.

■ 23. Amend § 60.4380 by revising paragraph (b)(3) to read as follows:

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

* * * * *

(b) * * *

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

* * * * *

■ 24. Revise § 60.4395 to read as follows:

**§ 60.4395 What must I submit my reports?**

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.

■ 25. Amend § 60.4400 by revising paragraphs (a)(1)(i) and (ii) and (b)(2) to read as follows:

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

(a) * * *

(1) * * *

(i) Measure the $NO_X$ concentration (in parts per million (ppm)), using EPA Method 7E in appendix A–4 to this part, EPA Method 20 in appendix A–7 to this part, EPA Method 320 in appendix A of part 63 of this chapter, or ASTM D6348–12 (Reapproved 2020) (incorporated by reference, see § 60.17). For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A to this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the $NO_X$ emission rate:

Equation 1 to Paragraph (a)(1)(i)

$$E = \frac{1.194 \times 10^{-7} \times (NO_X)_c \times Q_{std}}{P} (Eq. 1)$$

Where:

E = $NO_X$ emission rate, in lb/MWh;

$1.194 \times 10^{-7}$ = conversion constant, in lb/dscf-ppm;

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

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

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

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

* * * * *

(b) * * *

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total $NO_X$ emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation within 25 percent of 100 percent of the peak load rating of the duct burners or the highest achievable load if at least 75 percent of the peak load of the duct burners cannot be achieved during the performance test.

* * * * *

■ 26. Amend § 60.4405 by revising paragraph (a) to read as follows:

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

* * * * *

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

* * * * *

■ 27. Amend § 60.4415 by revising paragraphs (a) introductory text and (a)(2) through (4) to read as follows:

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

(a) You must conduct an initial performance test, as required in § 60.8. An owner or operator of an affected facility complying with the fuel-based standard may use 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. Subsequent $SO_2$ performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are four methodologies that you may use to conduct the performance tests.

* * * * *

(2) Periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287–97 (Reapproved 2002) (incorporated by reference, see § 60.17) for gaseous fuels or ASTM D4177–95 (Reapproved 2000) (incorporated by reference, see § 60.17) for liquid fuels. For manual sampling of gaseous fuels, follow API Manual of Petroleum Measurement Standards, Chapter 14, Section 1; GPA 2166–17; or ISO 10715:1997(E) (all incorporated by reference, see § 60.17). For manual sampling of liquid fuels, follow GPA 2174–14 or the procedures for manual pipeline sampling in section 14 of ASTM D4057–95 (Reapproved 2000) (both incorporated by reference, see § 60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129–00 (Reapproved 2005), or alternatively D1266–98 (Reapproved 2003), D1552–03, D2622–05, D4294–03, D5453–05, D5623–19, or D7039–15a (all incorporated by reference, see § 60.17); or

(ii) For gaseous fuels, ASTM D1072–90 (Reapproved 1999), or alternatively D3246–05, D4084–05, D4468–85 (Reapproved 2000), D4810–88 (Reapproved 1999), D6228–98 (Reapproved 2003), D6667–04, or GPA 2140–17, 2261–19, or 2377–86 (all incorporated by reference, see § 60.17).

(3) Measure the $SO_2$ concentration (in parts per million (ppm)), using EPA Method 6, 6C, 8, or 20 in appendix A to 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 to this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the $SO_2$ emission rate:

Equation 1 to Paragraph (a)(3)

$$E = \frac{1.664 \times 10^{-7} \times (SO_2)_c \times Q_{std}}{P} (Eq. 1)$$

Where:

E = $SO_2$ emission rate, in lb/MWh;

$1.664 \times 10^{-7}$ = conversion constant, in lb/dscf-ppm;

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

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

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

MW, calculated according to § 60.4350(f)(2); or

(4) Measure the $SO_2$ and diluent gas concentrations, using either EPA Method 6, 6C, or 8 and 3A, or 20 in appendix A to this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A to this part to calculate the $SO_2$ emission rate in lb/MMBtu. Then, use equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the $SO_2$ emission rate in lb/MWh.

* * * * *

■ 28. Amend § 60.4420 by:

■ a. Adding the definition of *Byproduct* in alphabetical order;

■ b. Revising the definitions of *Duct burner* and *Emergency combustion turbine;*

■ c. Adding the definitions of *Firefighting turbine, Garrison facility,* and *Low-Btu gas* in alphabetical order;

■ d. Revising the definitions of *Natural gas* and *Noncontinental area;*

■ e. Adding the definition of *Offshore turbine* in alphabetical order;

■ f. Revising the definition of *Stationary combustion turbine;* and

■ g. Adding the definition of *Temporary combustion turbine* in alphabetical order.

The additions and revisions read as follows:

**§ 60.4420 What definitions apply to this subpart?**

* * * * *

*Byproduct* means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, pulp and paper mills, or other industrial facilities (except natural gas and fuel oil).

* * * * *

*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.

* * * * *

*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 (*e.g.,* firefighting turbine) or flood, etc. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, agencies, or departments, voluntary consensus standards, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the combustion turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines. Emergency combustion turbines do not include combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors.

* * * * *

*Firefighting turbine* means any stationary combustion turbine that is used solely to pump water for extinguishing fires.

*Garrison facility* means any permanent military installation.

* * * * *

*Low-Btu gas* means any gaseous fuels that have heating values less than 26 megajoules per standard cubic meter (MJ/scm) (700 Btu/scf).

*Natural gas* means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane) that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must be composed of at least 70 percent methane by volume and have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Unless refined to meet this 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 sulfur content or heating value.

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

*Offshore turbine* means a stationary combustion turbine located on a platform or facility in an ocean, territorial sea, the outer continental shelf, or the Great Lakes of North America and stationary combustion turbines located in a coastal management zone and elevated on a platform.

* * * * *

*Stationary combustion turbine* means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. Portable combustion turbines are excluded from the definition of ''stationary combustion turbine,'' and not regulated under this part, if the turbine meets the definition of ''nonroad engine'' under title II of the Clean Air Act and applicable regulations and is certified to meet emission standards promulgated pursuant to title II of the Clean Air Act, along with all related requirements.

*Temporary combustion turbine* means a combustion turbine that is intended to and remains at a single stationary source (or group of stationary sources located within a contiguous area and under common control) for 24 consecutive months or less.

* * * * *

■ 29. Revise table 1 to subpart KKKK to read as follows:

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

| Combustion turbine type | Combustion turbine heat input at peak load (HHV) | $NO_X$ emission standard |
|---|---|---|
| New turbine firing natural gas, electric generating | ≤50 MMBtu/h | 42 ppm at 15 percent $O_2$ or 290 ng/J of useful output (2.3 lb/MWh). |

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

| Combustion turbine type | Combustion turbine heat input at peak load (HHV) | $NO_X$ emission standard |
|---|---|---|
| New turbine firing natural gas, mechanical drive | ≤50 MMBtu/h | 100 ppm at 15 percent $O_2$ or 690 ng/J of useful output (5.5 lb/MWh). |
| New turbine firing natural gas | >50 MMBtu/h and ≤850 MMBtu/h | 25 ppm at 15 percent $O_2$ or 150 ng/J of useful output (1.2 lb/MWh). |
| New, modified, or reconstructed turbine firing natural gas | >850 MMBtu/h | 15 ppm at 15 percent $O_2$ or 54 ng/J of useful output (0.43 lb/MWh) |
| New turbine firing fuels other than natural gas, electric generating | ≤50 MMBtu/h | 96 ppm at 15 percent $O_2$ or 700 ng/J of useful output (5.5 lb/MWh). |
| New turbine firing fuels other than natural gas, mechanical drive | ≤50 MMBtu/h | 150 ppm at 15 percent $O_2$ or 1,100 ng/J of useful output (8.7 lb/MWh). |
| New turbine firing fuels other than natural gas | >50 MMBtu/h and ≤850 MMBtu/h | 74 ppm at 15 percent $O_2$ or 460 ng/J of useful output (3.6 lb/MWh). |
| New, modified, or reconstructed turbine firing fuels other than natural gas. | >850 MMBtu/h | 42 ppm at 15 percent $O_2$ or 160 ng/J of useful output (1.3 lb/MWh). |
| Modified or reconstructed turbine | ≤50 MMBtu/h | 150 ppm at 15 percent $O_2$ or 1,100 ng/J of useful output (8.7 lb/MWh). |
| Modified or reconstructed turbine firing natural gas | >50 MMBtu/h and ≤850 MMBtu/h | 42 ppm at 15 percent $O_2$ or 250 ng/J of useful output (2.0 lb/MWh). |
| Modified or reconstructed turbine firing fuels other than natural gas | >50 MMBtu/h and ≤850 MMBtu/h | 96 ppm at 15 percent $O_2$ or 590 ng/J of useful output (4.7 lb/MWh). |
| Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F. | ≤300 MMBtu/h or ≤30 MW output | 150 ppm at 15 percent $O_2$ or 1,100 ng/J of useful output (8.7 lb/MWh). |
| Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F. | >300 MMBtu/h and >30 MW output | 96 ppm at 15 percent $O_2$ or 590 ng/J of useful output (4.7 lb/MWh). |
| Heat recovery units operating independent of the combustion turbine. | All sizes | 54 ppm at 15 percent $O_2$ or 110 ng/J of useful output (0.86 lb/MWh). |
| Combustion turbines bypassing the heat recovery unit | >50 MMBtu/h | 25 ppm at 15 percent $O_2$ or 150 ng/J of useful output (1.2 lb/MWh). |

■ 30. Add subpart KKKKa to read as follows:

## Subpart KKKKa—Standards of Performance for Stationary Combustion Turbines

Sec.



## 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 December 13, 2024.

## 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 December 13, 2024, 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 and duct burner(s) that are associated with a combustion turbine subject to this subpart.

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

(c) Duct burners are not subject to subpart 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.

(d) If you own or operate a stationary combustion turbine (including a combined cycle combustion turbine or a CHP combustion turbine) that commenced construction, modification, or reconstruction on or before December 13, 2024, 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 subpart 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.

(e) If you own or operate a combined cycle combustion turbine or combined heat and power combustion turbine, and changes are made after December 13, 2024, to allow the existing combustion turbine to also operate in simple cycle mode and those changes are determined a modification for NSPS purposes, this subpart shall apply to the combustion turbine only as it operates in simple cycle mode, and not to its existing configuration in combined cycle mode.

### § 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.

(d) Stationary gas turbines subject to title II of the Clean Air Act are not subject to this subpart.

## 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. If you choose to use $NO_X$ CEMS, input-based emission rates and standards are determined on a 4-operating-hour rolling basis and output-based emission rates and standards are determined on a 30-operating-day rolling basis. Mass-based emission rates are determined on both a 4-operating-hour and 12-calendar-month rolling 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 (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. For hours with multiple emission standards, the applicable standard for that hour is determined based on the condition, excluding periods of monitor downtime, that corresponds to the highest emissions standard. For example, if your affected facility operates at 70 percent or less of its base load rating for any portion of the hour, the emission limit(s) in table 1 to this subpart for combustion turbines operating at 70 percent or less of base load rating shall apply for that hour.

(2) As an alternative to the requirements specified in paragraph (b)(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 only natural gas is combusted, you must meet the $NO_X$ emission standard as determined by the applicable size category in table 1 or 2 to this subpart, as applicable, which corresponds to a stationary combustion turbine firing natural gas for that operating hour. During each operating hour when the heat input (based on the HHV of the fuels) of the combustion turbine engine is less than 50 percent natural gas (*i.e.,* 50 percent or greater non-natural gas), as defined in § 60.4420a, at any point during an operating hour, you must meet the $NO_X$ emission standard as determined by the applicable size category in table 1 or 2 to this subpart, as applicable, which corresponds to a stationary combustion turbine firing fuels other than natural gas for that operating hour. During each operating hour when the heat input to the combustion turbine engine is greater than 50 percent natural gas, as defined in § 60.4420a, during an entire operating hour while combusting some portion of non-natural gas fuels, you must meet the $NO_X$ emission standard as determined by prorating the applicable $NO_X$ standards, based on the applicable size category in table 1 or 2 to this subpart, as applicable, by the heat input from each fuel type.

(4) If you have two or more combustion turbine engines share a common stack, are connected to a single electric generator, or share a steam turbine, except as provided for in paragraph (b)(4)(i) of this section, you must monitor the hourly $NO_X$ emissions at the common stack in lieu of monitoring each combustion turbine separately. If you choose to comply with the output-based emissions standard, the hourly gross or net energy output (electric, thermal, or mechanical, as applicable) must be the sum of the hourly loads for the individual affected combustion turbines, and you must

express the operating time as ''stack operating hours'' (as defined in 40 CFR 72.2). If you attain compliance with the most stringent applicable emission standard in table 1 or 2 to this subpart, as applicable, at the common stack, each affected combustion turbine sharing the stack is in compliance.

(i) As an alternative to the requirements in this paragraph (b)(4), you may either:

(A) Monitor each combustion turbine separately by measuring the $NO_X$ emissions prior to mixing in the common stack; or

(B) Apportion the $NO_X$ emissions based on the unit's heat input contribution to the total heat input associated with the common stack and the appropriate F-factors. If you chose to comply with the output-based standard, output from a common steam turbine shall be apportioned based on the heat input to each combustion turbine. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the $NO_X$ emissions. The Administrator may approve such alternate methods for apportioning the $NO_X$ emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(ii) [Reserved]

(c) Stationary combustion turbines that meet at least one of the specifications described in paragraphs (c)(1) through (4) 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 byproduct fuels for which a facility-specific $NO_X$ emissions standard has been established by the Administrator or delegated authority according to the requirements of paragraphs (c)(3)(i) and (ii) of this section is exempt from the emission limits specified in tables 1 and 2 to this subpart.

(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 byproduct fuel, is unable to comply with the applicable $NO_X$ emission standard determined using table 1 or 2 to this subpart.

(ii) If the Administrator or delegated authority approves the request, a facility-specific $NO_X$ emissions standard will be established in a manner that the Administrator or delegated authority determines to be consistent with minimizing $NO_X$ emissions.

(4) Military combustion turbines for use in other than a garrison facility and military combustion turbines installed for use as military training facilities.

(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).

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

You must meet the emission limits specified in table 1 or 2 to this subpart. If your turbine operates below 70 percent of the base load rating at any point during an operating hour, the part load standard is applicable during the entire operating hour. For non-part load operating hours, if your stationary combustion turbine's heat input is greater than or equal to 50 percent fuels other than natural gas at any point during an operating hour, your combustion turbine must meet the corresponding limit for non-natural gas. For non-part load operating hours when your total heat input is greater than 50 percent natural gas while combusting some portion of non-natural gas fuels, you must meet the corresponding emissions standard as determined by prorating the applicable $NO_X$ standards, based on the applicable size category in table 1 or 2 to this subpart, as applicable, by the heat input from each fuel type.

### § 60.4330a What $SO_2$ emissions standard must I meet?

(a) Except as provided for in paragraphs (b) through (e) of this section, for each new, modified, or reconstructed 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 new, modified, or reconstructed stationary combustion turbine combusting 50 percent or more low-Btu gas per calendar month based on total heat input (using the HHV 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 feet (scf)); or

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

(c) For each new, modified, or reconstructed 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 new, modified, or reconstructed 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.

### § 60.4331a What are the requirements for operating a stationary temporary combustion turbine?

(a) Notwithstanding any other provision of this subpart, you may operate a small- or medium-size stationary combustion turbine (*i.e.,* a combustion turbine with a base load rating less than or equal to 850 MMBtu/h) at a single location for up to 24 consecutive months, so long as you comply with all of the requirements in paragraphs (b) through (e) of this section.

(b) You must meet the $NO_X$ emissions standard for stationary temporary combustion turbines in table 1 to this subpart and the applicable $SO_2$ emissions standard in § 60.4330a.

(c) Unless you elect to demonstrate compliance through the otherwise-applicable monitoring, recordkeeping, and reporting requirements of this subpart, compliance with the $NO_X$ emissions standard must be demonstrated through maintaining the documentation in paragraphs (c)(1) and (2) of this section on-site:

(1) Each stationary temporary combustion turbine in use at the location has a manufacturer's emissions guarantee at or below the full load $NO_X$ emissions standard in table 1 to this subpart; and

(2) Each such turbine has been performance tested at least once in the prior 5 years as meeting the $NO_X$ emissions standard in table 1 to this subpart.

(d) Unless you elect to demonstrate compliance through the otherwise-applicable monitoring, recordkeeping, and reporting requirements of this subpart, compliance with the $SO_2$ emissions standard must be demonstrated through complying with the provisions in § 60.4372a.

(e) The conditions in paragraphs (e)(1) through (3) of this section apply in determining whether your stationary combustion turbine qualifies as a stationary temporary combustion turbine.

(1) The turbine may only be located at the same stationary source (or group of stationary sources located within a contiguous area and under common control) for a total period of 24 consecutive months. This is the total period of residence time allowed after the turbine commences operation at the location, regardless of whether the turbine is in operation for the entire 24 consecutive month period.

(2) Any temporary combustion turbine that replaces a temporary combustion turbine at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The relocation of a stationary temporary combustion turbine within a single stationary source (or group of stationary sources located within a contiguous area and under common control) while performing the same or similar function (*i.e.,* serving the same electric, mechanical, or thermal load) does not restart the 24-calendar month residence time period.

**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 (6) of this section.

(1) Except as provided for in paragraphs (b)(2) through (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 26 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 14-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 or 10 operating days, whichever is longer, 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 168 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 168 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 (b)(4) 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 168 hours of operation since the date on which the previous performance test was conducted. When the facility has operated more than 168 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 (b)(5)(i) through (v) of this section.

(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 paragraph (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) or parts per million (ppm) input-based 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 an input-based 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 or ppm) 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 paragraph (e)(1) or (2) 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 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 prorated (by heat input) emissions standards of each of the individual combustion turbine engines that are exhausted through the single heat recovery steam generating unit.

(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 paragraph (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.

(g) If you elect to comply with the mass-based standard, you must demonstrate continuous compliance using either a CEMS for measuring $NO_X$ emissions according to the provisions in § 60.4345a or using the methodology in appendix E to part 75 of this chapter.

**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 § 75.19 of this chapter; 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) If you opt to demonstrate compliance according to the procedures described in paragraph (a)(3) of this section, 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.

(1) Selection of the operating parameters used to comply with this paragraph (b) 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 § 75.19(c)(1)(iv)(H) of this chapter.

### § 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 confirmed or 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 or has had the combustion turbine replaced with an overhauled turbine engine as part of an exchange program is not required to perform the subsequent recalibration until 45 calendar days after the next operating day.

### § 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 or mass-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 monitor 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 either a fuel flow meter (or flow meters) or an $O_2$ or $CO_2$ CEMS and a stack flow monitor. 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.

(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 monitor 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. Alternatively, span values determined according to section 2.1.2 in appendix A to part 75 may be used. 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, you may use $NO_X$ and diluent CEMS that are installed and certified according to appendix A to part 75 in lieu of Procedure 1 in appendix F to this part and the requirements of § 60.13, except that the relative accuracy test audit (RATA) of the CEMS must be performed on a lb/MMBtu basis. For stationary combustion turbines that use post-combustion technology to reduce emissions of $NO_X$ to comply with the requirements of this subpart, you may use $NO_X$ and diluent CEMS that are installed and certified according to appendix A to part 75 in lieu of Procedure 1 in appendix F to this part and the requirements of § 60.13 with approval from the Administrator or delegated authority, 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.

(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). 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 (f) 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.

**§ 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, 30-operating-days, or 12-calendar-month), 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 or lbs, as applicable, using the appropriate equation from EPA Method 19 in appendix A–7 to 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. For units complying with the 12-calendar-month mass-based standard, emissions for hours of missing data shall be estimated by using the average emissions rate of non-out-of-control hours within ±10 percent of the hour of missing data within the 12-calendar-month period. If non-out-of-control data is not available, the maximum hourly emissions rate during the 12-calendar-month period shall be used.

(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 or ppm for units complying with the input-based standard, using lbs for units complying with the mass-based standard, or lb/MWh or kg/MWh for units complying with the output-based standard:

(1) 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 1 and 2 to this paragraph (f)(1):

Equation 1 to Paragraph (f)(1)

$$P = \frac{(Pe)_t}{T} + \frac{(Pe)_c}{T} - Pe_A + P_s + P_o \text{ (Eq. 1)}$$

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;

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

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.

Equation 2 to Paragraph (f)(1)

$$P_s = \frac{Q_m \times H}{3.413 \times 10^6 \ Btu/MWh} \quad \text{(Eq. 2)}$$

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

$3.413 \times 10^6$ = Conversion factor from Btu to MWh.

(2) For mechanical drive applications complying with the output-based standard, use equation 3 to this paragraph (f)(2):

Equation 3 to Paragraph (f)(2)

$$E = \frac{(NO_x)_m}{BL \times AL} \quad \text{(Eq. 3)}$$

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.

(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. Calculate a 4-operating-hour rolling average $NO_X$ emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (*e.g.,* a valid 4-operating-hour rolling average $NO_X$ emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).

(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 in table 1 to this subpart, using equation 4 to this paragraph (g)(2).

Equation 4 to Paragraph (g)(2)

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

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)(1) 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 output-based emissions rate standard, calculate the measured emissions rate using equation 5 to this paragraph (h)(1) and calculate the applicable emissions standard using equation 6 to this paragraph (h)(1). If you elect to comply with the applicable output-based emissions rate standard and determine the heat input on an hourly basis, calculate the 30-operating-day rolling average $NO_X$ emissions rate using equation 5, and determine the applicable 30-operating-day rolling average $NO_X$ emissions standard, calculated using values in table 1 to this subpart, using equation 6. Hours are not subcategorized by load for the purposes of determining the applicable output-based standard. The emissions standard for all hours, regardless of load, is the otherwise applicable full load emissions standard.

Equation 5 to Paragraph (h)(1)

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

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.

Equation 6 to Paragraph (h)(1)

$$E = E_{NG} \times \frac{H_{NG}}{H_T} + E_{non-NG} \times \frac{H_{non-NG}}{H_T} \qquad (Eq. 6)$$

E = 30-operating-day rolling $NO_X$ emissions standard (lb/MWh or kg/MWh);
$E_{NG}$ = 30-operating-day emissions standard for natural gas-fired combustion turbines (lb/MWh or kg/MWh);
$E_{non\text{-}NG}$ = 30-operating-day emissions standard for non-natural gas-fired combustion turbines (lb/MWh or kg/MWh);
$H_{NG}$ = Hours of operation combusting natural gas during the 30-operating-day period;
$H_{non\text{-}NG}$ = Hours of operation combusting non-natural gas fuels during the 30-operating-day period; and
$H_T$ = Total hours of operation during the 30-operating-day period.

(2) If you elect to comply with the applicable output-based emissions rate standard and elect to not determine the heat input on an hourly basis, the applicable 30-operating-day emissions rolling $NO_X$ standard is the most stringent standard applicable to the combustion turbine. The 30-operating-day rolling $NO_X$ emissions rate is determined as the sum of the hourly emissions divided by the sum of the gross or net output over the 30-operating-day period.

(i) For each combustion turbine demonstrating compliance on a mass-based standard, you must determine excess $NO_X$ emissions on both a rolling 4-operating-hour and rolling 12-calendar-month basis using the $NO_X$ CEMS data and procedures specified in paragraphs (i)(1) through (4) of this section as applicable to the $NO_X$ emissions standard in table 2 to this subpart. In addition, during system emergencies each combustion turbine must determine excess $NO_X$ emissions using the procedures specified in paragraph (i)(5) of this section.

(1) For each 4-operating-hour period, compute the 4-operating-hour rolling $NO_X$ emissions as the sum of the hourly $NO_X$ emissions for a given operating hour and the 3 operating hours preceding that operating hour. Calculate a 4-operating-hour $NO_X$ emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (*e.g.,* a valid 4-operating-hour rolling $NO_X$ emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).

(2) Calculate the applicable 4-operating-hour rolling $NO_X$ emissions standard, calculated using hourly values in table 2 to this subpart, using equation 7 to this paragraph (i)(2).

Equation 7 to Paragraph (i)(2)

$$E = \sum_{i=1}^{4} (E_i) \quad (\text{Eq. } 7)$$

Where:
E = 4-operating-hour rolling $NO_X$ emissions (kg or lbs); and
$E_i$ = Hourly $NO_X$ emissions rate or emissions standard for operating hour ''i'' (kg or lbs).

(3) For each 12-calendar-month period, compute the 12-calendar-month rolling $NO_X$ emissions as the sum of the hourly $NO_X$ emissions for a given month and the 11 calendar months preceding the calendar month. Emissions during system emergencies are not included when calculating the 12-calendar-month emissions rate.

(4) Calculate the applicable 12-calendar-month rolling $NO_X$ emissions standard, calculated using hourly values in table 2 to this subpart, using equation 8 to this paragraph (i)(4). Heat input during system emergencies is not included when calculating the 12-calendar-month emissions standard.

Equation 8 to Paragraph (i)(4)

$$E = E_{NG} \times \frac{H_{NG}}{H_T} + E_{Non-NG} \times \frac{H_{non-NG}}{H_T} \quad (\text{Eq. } 8)$$

Where:
E = 12-calendar-month rolling $NO_X$ emissions (tonnes or tons);
$E_{NG}$ = 12-calendar-month emissions standard for natural gas-fired combustion turbines (tonnes or tons);
$E_{non\text{-}NG}$ = 12-calendar-month emissions standard for non-natural gas-fired combustion turbines (tonnes or tons);
$H_{NG}$ = Hours of operation combusting natural gas during the 12-calendar-month period;
$H_{non\text{-}NG}$ = Hours of operation combusting non-natural gas fuels during the 12-calendar-month period; and
$H_T$ = Total hours of operation during the 12-calendar-month period.

(5) During system emergencies during which the owner or operator elects to not include emissions or heat input in the 12-calendar month calculations, the applicable average natural gas-fired emissions standard is 0.83 lb $NO_X$/MW-rated output (1.8 lb $NO_X$/MW-rated output when firing non-natural gas) or the current emissions rate necessary to comply with the 12-calendar month natural gas-fired emissions standard of 0.48 tons $NO_X$/MW-rated output (0.81 tons $NO_X$/MW-rated output when firing non-natural gas) whichever is more stringent. For example, if a combustion turbine operated for 4,000 hours during the current 12-calendar month period the applicable average natural gas-fired emissions standard during the system emergency would be 0.24 lb $NO_X$/MW-rated output and the applicable average non-natural gas-fired emissions standard during the system emergency would be 0.41 lb $NO_X$/MW-rated output.

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

(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 (Reapproved 2002) (incorporated by reference, see § 60.17) for gaseous fuels or ASTM D4177–95 (Reapproved 2000) (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 (Reapproved 2000) (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 paragraph (c)(1) or (2) of this section, as applicable to the fuel type.

(1) For the sulfur content of liquid fuels, ASTM D129–00 (Reapproved 2005), or alternatively D1266–98 (Reapproved 2003), D1552–03, D2622–05, D4294–03, D5453–05, D5623–24, or D7039–24 (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 (Reapproved 2000), D6667–04, or D5504–20 (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 (Reapproved 1999), D5504–20, or D6228–98 (Reapproved 2003), or Gas Processors Association Standard 2140–17 or 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), D4891–89 (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 paragraph (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) or (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. Your stationary combustion turbine may not cause to be discharged into the atmosphere any gases that contain $SO_2$ in excess of:

(1) 110 ng $SO_2$/J (0.90 lb $SO_2$/MWh) gross energy output or 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input; or

(2) 780 ng $SO_2$/J (6.2 lb $SO_2$/MWh) gross energy output or 180 ng $SO_2$/J (0.42 lb $SO_2$/MMBtu) heat input if your combustion turbine is in a noncontinental area.

**§ 60.4374a How do I demonstrate compliance with my $SO_2$ emissions standard and determine excess emissions using 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 to this part;

(2) Quarterly accuracy determinations and daily calibration drift tests must be performed according to Procedure 1 in appendix F to 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. Alternatively, $SO_2$ span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(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 1 to paragraph (g)(1) of this section for units complying with the output-based standard:

(1) For simple cycle operation:

Equation 1 to Paragraph (g)(1)

$$E = \frac{(SO_2)_h \times Q}{P} \quad \text{(Eq. 1)}$$

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 monitor, 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 2 and 3 to this paragraph (g)(2); and any auxiliary load.

Equation 2 to Paragraph (g)(2)

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

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;

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

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.

Equation 3 to Paragraph (g)(2)

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

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 rate in lb;
H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb; and
$3.413 \times 10^6$ = Conversion factor from Btu to MWh.

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

Equation 4 to Paragraph (g)(3)

$$\mathrm{E} = \frac{(\mathrm{SO_2})_\mathrm{m}}{\mathrm{BL} \times \mathrm{AL}} \quad \text{(Eq. 4)}$$

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. Calculate a 4-operating-hour rolling average $SO_2$ emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (*e.g.,* a valid 4-operating-hour rolling average $SO_2$ emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).

(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 5 to this paragraph (h)(2).

Equation 5 to Paragraph (h)(2)

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

Where:

E = 4-operating-hour rolling average $SO_2$ 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 operating 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. 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 6 to this paragraph (i).

Equation 6 to Paragraph (i)

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

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.

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

(c) 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.

(d) 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 168 operating hours since the date the previous performance test was required to be conducted.

(e) 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 paragraph (g) of this section. You must submit the report in a file format generated using the EPA's Electronic Reporting Tool (ERT). Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) accompanied by the other information required by § 60.8(f)(2) in PDF format.

(f) You must submit to the Administrator semiannual reports of the following recorded information. Beginning on January 15, 2027, or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (g) of this section. The date report templates 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.

(g) If you are required to submit notifications or reports following the procedure specified in this paragraph (g), you must submit notifications or reports 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 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 in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. 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. 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. 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 earlier in this paragraph (g).

(1) 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. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Combustion Turbine Sector Lead. 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.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer, Mail Drop: C404–02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. In addition to the OAQPS Document Control Officer, ERT files should also be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should also be sent to the attention of the Stationary Combustion Turbine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(h) 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 (h)(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 5 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.

(i) 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 (i)(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 5 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.

(j) 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) and (2) of this section.

(1) An excess emission that must be reported is any unit operating period in which the 4-operating-hour average $NO_X$ emissions rate, 30-operating-day rolling average $NO_X$ emissions rate, 4-hour mass-based emissions rate, or the 12-calendar-month mass-based 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 that you use to calculate the emission rate, as applicable, used to determine compliance, 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.

(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 that are used to calculate the emission rate, as applicable, used to determine compliance, 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) and (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 that you use to calculate the emission rate, as applicable, used to determine compliance, 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 to this part, EPA Method 20 in appendix A–7 to this part, EPA Method 320 in appendix A to part 63 of this chapter, or ASTM D6348–12 (Reapproved 2020) (incorporated by reference, see § 60.17). 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 to this part, and measure and record the electrical and thermal output from the unit. Then, use equation 1 to this paragraph (b)(1) to calculate the $NO_X$ emissions rate:

Equation 1 to Paragraph (b)(1)

$$E = \frac{1.194 \times 10^{-7} \times (NO_x)_c \times Q_{std}}{P} \quad \text{(Eq. 1)}$$

Where:

E = $NO_X$ emissions rate, in lb/MWh;
$1.194 \times 10^{-7}$ = 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 to this part and EPA Method 3A in appendix A–2 to this part, or EPA Method 20 in appendix A–7 to 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 to this part or EPA Method 20 in appendix A–7 to 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 monitor, 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 to this part to calculate the $NO_X$ emissions rate in lb/MMBtu. Then, use equations 1 and, if necessary, 2 and 3 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 to this part or EPA Method 1 in appendix A–1 to 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 to 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 ±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 within ±25 percent of 100 percent of the base load rating of the duct burners or the highest achievable load if at least 75 percent of the base load rating of the duct burners cannot be achieved 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 to this part or EPA Method 7E in appendix A–4 to 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.

**§ 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 ±25 percent of 100 percent of the base load rating while the source is combusting the fuel that is a normal primary fuel for that source. 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, ppm, lb/MWh, or kgs, does not exceed the emissions standard.

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

(a) If you are 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.

(b) If you are 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 Method 6, 6C, or 8 in appendix A–4 to this part or EPA Method 20 in appendix A–7 to 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 to this part, and measure and record the electrical and thermal output from the unit. Then use equation 1 to this paragraph (b)(1) to calculate the $SO_2$ emissions rate:

Equation 1 to Paragraph (b)(1)

$$E = \frac{1.664 \times 10^{-7} \times (SO_2)_c \times Q_{std}}{P} \quad \text{(Eq. 1)}$$

Where:

E = $SO_2$ emissions rate, in lb/MWh;

$1.664 \times 10^{-7}$ = 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 Method 6, 6C, or 8 in appendix A–4 to this part and EPA Method 3A in appendix A–2 to this part, or EPA Method 20 in appendix A–7 to this part. 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 monitor, 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 to this part to calculate the $SO_2$ emissions rate in lb/MMBtu. Then, use equations 1 and, if necessary, 2, 3, and 4 in § 60.4374a to calculate the $SO_2$ emissions rate in lb/MWh.

## Other Requirements and Information

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

(a) 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.

(b) Small, medium, and low utilization large combustion turbines that are subject to this subpart and are not a "major source" or located at a "major source" (as that term is defined at 42 U.S.C. 7661(2)) are exempt from the requirements of 42 U.S.C. 7661a(a).

### § 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?

As used in this subpart, all terms not defined in this section will have the meaning given them in the Clean Air Act and in subpart A 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. Heat input during a system emergency as defined in § 60.4420a is excluded when determining the annual capacity factor. 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. The base load rating does not include any potential heat input to an HRSG.

*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 $CO_2$.

*Byproduct* means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, pulp and paper mills, or other industrial facilities (except natural gas and fuel oil).

*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).

*District energy system* means a central plant producing hot water, steam, and/or chilled water, which then flows through a network of insulated pipes to provide hot water, space heating, and/or air conditioning for commercial, institutional, or residential buildings.

*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.

*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 (*e.g.,* firefighting turbine) or flood, etc. 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 recommended by Federal, State, or local government, agencies, or departments, voluntary consensus standards, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the combustion turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines. Emergency combustion turbines do not include combustion turbines used as peaking units at electric utilities or combustion turbines at industrial facilities that typically operate at low capacity factors.

*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 this part and part 61 of this chapter, requirements within any applicable State Implementation Plan, and any permit requirements established under § 52.21 or §§ CFR 51.18 and 51.24 of this chapter.

*Firefighting combustion turbine* means any stationary combustion turbine that is used solely to pump water for extinguishing fires.

*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 (incorporated by reference, see § 60.17).

*Garrison facility* means any permanent military installation.

*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 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).

(4) For a district energy CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of useful thermal output on a 12-calendar-month 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 (*e.g.,* steam delivered to an industrial process) divided by 0.95.

*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.

*High-utilization source* means a new medium or large stationary combustion turbine with a 12-calendar-month capacity factor greater than 45 percent.

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

*Large combustion turbine* means a stationary combustion turbine with a base load rating greater than 850 MMBtu/h of heat input.

*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).

*Low-utilization source* means a new medium or large stationary combustion turbine with a 12-calendar-month capacity factor less than or equal to 45 percent.

*Medium combustion turbine* means a stationary combustion turbine with a base load rating greater than 50 MMBtu/h and less than or equal to 850 MMBtu/h of heat input.

*Natural gas* means a fluid mixture of hydrocarbons, composed of at least 70 percent methane by volume, that has a gross calorific value between 35 and 41 MJ/scm (950 and 1,100 Btu/scf), and that maintains a gaseous state under ISO conditions. Unless processed to meet this 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.

*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 CHP facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-calendar-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.

(3) For district energy CHP facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-calendar-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 divided by 0.95.

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

*Offshore turbine* means a stationary combustion turbine located on a platform or facility in an ocean, territorial sea, the outer continental shelf, or the Great Lakes of North America and stationary combustion turbines located in a coastal management zone and elevated on a platform.

*Operating day* means a 24-hour period between 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.

*Small combustion turbine* means a stationary combustion turbine with a base load rating less than or equal to 50 MMBtu/h of heat input.

*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 and/or pump, 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), 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. Portable combustion turbines are excluded from the definition of ''stationary combustion turbine,'' and not regulated under this part, if the turbine meets the definition of ''nonroad engine'' under title II of the Clean Air Act and applicable regulations and is certified to meet emissions standards promulgated pursuant to title II of the Clean Air Act, along with all related requirements.

*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.

*System emergency* means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 1, 2, or 3, which should follow NERC Reliability Standard EOP–011–2, its successor, or equivalent.

*Temporary combustion turbine* means a combustion turbine that is intended to and remains at a single stationary source (or group of stationary sources located within a contiguous area and under common control) for 24 consecutive months or less.

*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 this part or part 75 of this chapter as applicable. For CEMS maintained according to part 75, the initial certification requirements in § 75.20 and appendix A to 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 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 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 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 part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 apply (except for qualifying commercial billing meters). Any out-of-control data is not considered valid data.

### TABLE 1 TO SUBPART KKKKa OF PART 60—NITROGEN OXIDE EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

| Combustion turbine type | Combustion turbine base load rated heat input (HHV) | Input-based $NO_X$ emission standard [1] | Optional output-based $NO_X$ standard [2] |
| --- | --- | --- | --- |
| New, firing natural gas with utilization rate >45 percent. | >850 MMBtu/h | 5 ppm at 15 percent $O_2$ or 7.9 ng/J (0.018 lb/MMBtu). | 0.054 kg/MWh-gross (0.12 lb/MWh-gross) 0.055 kg/MWh-net (0.12 lb/MWh-net). |
| New, firing natural gas with utilization rate ≤45 percent and with design efficiency ≥38 percent. | >850 MMBtu/h | 25 ppm at 15 percent $O_2$ or 40 ng/J (0.092 lb/MMBtu). | 0.38 kg/MWh-gross (0.83 lb/MWh-gross) 0.39 kg/MWh-net (0.85 lb/MWh-net). |
| New, firing natural gas with utilization rate ≤45 percent and with design efficiency <38 percent. | >850 MMBtu/h | 9 ppm at 15 percent $O_2$ or 14 ng/J (0.033 lb/MMBtu). | 0.17 kg/MWh-gross (0.37 lb/MWh-gross) 0.17 kg/MWh-net (0.38 lb/MWh-net). |
| New, modified, or reconstructed, firing non-natural gas. | >850 MMBtu/h | 42 ppm at 15 percent $O_2$ or 70 ng/J (0.16 lb/MMBtu). | 0.45 kg/MWh-gross (1.0 lb/MWh-gross) 0.46 kg/MWh-net (1.0 lb/MWh-net). |
| Modified or reconstructed, firing natural gas, at all utilization rates, with design efficiency ≥38 percent. | >850 MMBtu/h | 25 ppm at 15 percent $O_2$ or 40 ng/J (0.092 lb/MMBtu). | 0.38 kg/MWh-gross (0.83 lb/MWh-gross) 0.39 kg/MWh-net (0.85 lb/MWh-net). |
| Modified or reconstructed, firing natural gas, at all utilization rates, with design efficiency <38 percent. | >850 MMBtu/h | 15 ppm at 15 percent $O_2$ or 24 ng/J (0.055 lb/MMBtu). | 0.28 kg/MWh-gross (0.62 lb/MWh-gross) 0.29 kg/MWh-net (0.30 lb/MWh-net). |
| New, firing natural gas, at utilization rate >45 percent. | >50 MMBtu/h and ≤850 MMBtu/h. | 15 ppm at 15 percent $O_2$ or 24 ng/J (0.055 lb/MMBtu). | 0.20 kg/MWh-gross (0.43 lb/MWh-gross) 0.20 kg/MWh-net (0.44 lb/MWh-net). |
| New, firing natural gas, at utilization rate ≤45 percent. | >50 MMBtu/h and ≤850 MMBtu/h. | 25 ppm at 15 percent $O_2$ or 40 ng/J (0.092 lb/MMBtu). | 0.54 kg/MWh-gross (1.2 lb/MWh-gross) 0.56 kg/MWh-net (1.2 lb/MWh-net). |
| Modified or reconstructed, firing natural gas | >20 MMBtu/h and ≤850 MMBtu/h. | 42 ppm at 15 percent $O_2$ or 67 ng/J (0.15 lb/MMBtu). | 0.91 kg/MWh-gross (2.0 lb/MWh-gross) 0.92 kg/MWh-net (2.0 lb/MWh-net). |
| New, firing non-natural gas | >50 MMBtu/h and ≤850 MMBtu/h. | 74 ppm at 15 percent $O_2$ or 120 ng/J (0.29 lb/MMBtu). | 1.6 kg/MWh-gross (3.6 lb/MWh-gross) 1.6 kg/MWh-net (3.7 lb/MWh-net). |
| Modified or reconstructed, firing non-natural gas | >20 MMBtu/h and ≤850 MMBtu/h. | 96 ppm at 15 percent $O_2$ or 160 ng/J (0.37 lb/MMBtu). | 2.1 kg/MWh-gross (4.7 lb/MWh-gross) 2.2 kg/MWh-net (4.8 lb/MWh-net). |
| New, firing natural gas | ≤50 MMBtu/h | 25 ppm at 15 percent $O_2$ or 40 ng/J (0.092 lb/MMBtu). | 0.64 kg/MWh-gross (1.4 lb/MWh-gross) 0.65 kg/MWh-net (1.4 lb/MWh-net). |
| New, firing non-natural gas | ≤50 MMBtu/h | 96 ppm at 15 percent $O_2$ or 160 ng/J (0.37 lb/MMBtu). | 2.4 kg/MWh-gross (5.3 lb/MWh-gross) 2.5 kg/MWh-net (5.4 lb/MWh-net). |
| Modified or reconstructed, all fuels | ≤20 MMBtu/h | 150 ppm at 15 percent $O_2$ or 240 ng/J (0.55 lb/MMBtu). | 3.9 kg/MWh-gross (8.7 lb/MWh-gross) 4.0 kg/MWh-net (8.9 lb/MWh-net). |
| New, firing natural gas, either offshore turbines, turbines bypassing the heat recovery unit, and/or temporary turbines. | >50 MMBtu/h | 25 ppm at 15 percent $O_2$ or 40 ng/J (0.092 lb/MMBtu). | N/A. |
| Located north of the Arctic Circle (latitude 66.5 degrees north), operating at ambient temperatures less than 0° F (−18° C), modified or reconstructed offshore turbines, operated during periods of turbine tuning, byproduct-fired turbines, and/or operating at less than 70 percent of the base load rating. | ≤300 MMBtu/h | 150 ppm at 15 percent $O_2$ or 240 ng/J) 0.55 lb/MMBtu. | N/A. |
| Located north of the Arctic Circle (latitude 66.5 degrees north), operating at ambient temperatures less than 0° F (−18° C), modified or reconstructed offshore turbines, operated during periods of turbine tuning, byproduct-fired turbines, and/or operating at less than 70 percent of the base load rating. | >300 MMBtu/h | 96 ppm at 15 percent $O_2$ or 150 ng/J (0.35 lb/MMBtu). | N/A. |
| Heat recovery units operating independent of the combustion turbine. | All sizes | 54 ppm at 15 percent $O_2$ or 86 ng/J) 0.20 lb/MMBtu. | N/A. |

[1] Input-based standards are determined on a 4-operating-hour rolling average basis.
[2] Output-based standards are determined on a 30-operating-day average basis.

### TABLE 2 TO SUBPART KKKKa OF PART 60—ALTERNATIVE MASS-BASED $NO_X$ EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

| Combustion turbine type | 4-Hour emissions rate (lb $NO_X$/MW-rated output) | 12-Calendar-month emissions rate (ton $NO_X$/MW-rated output) |
| --- | --- | --- |
| Natural Gas | 0.38 kg $NO_X$/MW-rated output (0.83 lb $NO_X$/MW-rated output). | 0.44 tonne $NO_X$/MW-rated output (0.48 ton $NO_X$/MW-rated output). |
| Non-Natural Gas | 0.82 kg $NO_X$/MW-rated output (1.8 lb $NO_X$/MW-rated output). | 0.74 tonne $NO_X$/MW-rated output (0.81 ton $NO_X$/MW-rated output). |

### TABLE 3 TO SUBPART KKKKa OF PART 60—APPLICABILITY OF SUBPART A OF THIS PART TO THIS SUBPART

| 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. | |

TABLE 3 TO SUBPART KKKKa OF PART 60—APPLICABILITY OF SUBPART A OF THIS PART TO THIS SUBPART—Continued

| General provisions citation | Subject of citation | Applies to subpart KKKKa | Explanation |
| --- | --- | --- | --- |
| § 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) | Conducting performance tests | No | Overridden by § 60.4320a(d). |
| § 60.8(d)–(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 of this chapter or to information reported through ECMPS. |

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